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ANALYSIS OF TEST DATA FOR NO_X CONTROL IN GAS-AND OIL-FIRED UTILITY BOILERS

Aerospace Corporation

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ANALYSIS OF TEST DATA FOR NO_x CONTROL IN GAS- AND OIL-FIRED UTILITY BOILERS

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16. ABSTRACT
The report describes analyses of a large number of emissions, operating conditions, and boiler configuration data from full-scale, multiple-burner electric utility boilers using natural gas and low-sulfur oil fuels. Objectives of the study included: evaluation of the effects of combustion modifications on NOx emissions, in fundamental combustion terms; evaluation of techniques for further reductions in NOx emissions; and determination and substantiation of general mechanisms for observed combustion and flame stability problems. The report includes: (1) a discussion of the major combustion process modications resulting in NOx emission reductions due to two-stage combustion, burners out-of-service, combustion air temperature reduction, load reduction, and excess air variations; (2) estimates of NOx minima achievable in the boilers studied with current hardware; (3) estimates of most probable longer term hardware and operating condition modifications likely to yield ultimate NOx reductions with these fuels; (4) identification and verification of general mechanisms for the combustion and flame instabilities observed; and (5) a list of all of the hardware configurations, operating conditions, and NOx, CO, O2, and CO2 emissions data for 428 tests in eight full-scale, multiple-burner, face-fired electric utility boilers using natural gas and low-sulfur oil fuels.

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FOREWORD

This study was initially conceived in coordination with the Control Systems Laboratory of the Environmental Protection Agency (EPA), The Aerospace Corporation, and the Los Angeles Department of Water and Power. A great deal of testing on full-scale multiple-burner utility boilers has been accomplished in recent years by electric utility companies in the Los Angeles area, which has resulted in significant reductions in nitrogen oxide (NO_x) emissions. Data from this testing could be very valuable to utilities in other areas of the country where NO_x emission regulations are only beginning to require the large NO_x emission reductions already accomplished under the more stringent regulations in the Los Angeles area. An in-depth analysis of the data could also be valuable to supply feedback to further research in NO_x reduction techniques as well as to assist directly in pointing out combustion modification techniques likely to yield minimum NO_x emissions. It appeared that the increasing incidence of combustion and flame stability problems under operating conditions modified for the purpose of NO_x reduction represented a real and perhaps severe limitation on NO_x reduction by combustion modification methods. The Aerospace Corporation's long history of dealing with fundamental combustion processes and combustion stability problems in rocket engines was considered to be particularly applicable in the areas of concern.

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The study reported herein was conducted for the EPA, Control Systems Laboratory, Clean Fuels and Energy Branch, Combustion Research Section, Research Triangle Park, North Carolina, by The Aerospace Corporation. The study mainly concerns the analysis of data on combustion modifications for NO_x reduction with natural gas and low-sulfur oil fuels. The analysis of combustion and flame instability data is limited in this initial study to an effort to identify general mechanisms and to verify these with the available data. A followon study has already been initiated to conduct the same type of NO_x emission reduction study with coal fuels and with other furnace designs. Although the general mechanisms of the observed combustion and flame instability problems are believed identified and adequately verified, the more extensive stability analyses required to derive acceptable solutions have been deferred to a later study.

A brief introduction and a summary of the results of this study are contained in Section 1. Section 2 describes the analysis of NO_x reduction techniques, and Section 3 discusses the combustion and flame stability analyses. The appendixes include related details of these studies as well as a listing of the detailed test data used in the study.

ABSTRACT

This report describes The Aerospace Corporation analyses of a large quantity of emissions, operating conditions, and boiler configuration data from the full-scale multiple-burner electric utility boilers of the Los Angeles Department of Water and Power, using natural gas and low-sulfur oil fuels. Objectives of the study include (a) evaluation of the effects of combustion modifications on NO_x emissions in fundamental combustion terms, (b) evaluation of techniques for further reductions in NO_x emissions, and (c) determination and substantiation of general mechanisms for observed combustion and flame stability problems. The report includes the following results: (a) discussion of the major combustion process modifications resulting in NO_x emission reductions due to two-stage combustion, burners-out-of-service, combustion air temperature reduction, load reduction, and excess air variations; (b) estimates of NO_x minima achievable in the boilers studied with current hardware; (c) estimates of most probable longer-term hardware and operating condition modifications likely to yield ultimate NO_x reductions with these fuels; (4) identification and verification of general mechanisms for the combustion and flame instabilities observed; and (e) a listing of all of the hardware configuration, operating conditions, and NO_x, CO, O_2, and CO_2 emissions data for 428 tests in 8 full-scale, multiple-burner, face-fired electric utility boilers using natural gas and low-sulfur oil fuels.

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SECTION 1

INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Requirements for the reduction of nitrogen oxide (NO_x) emissions from large utility boilers were established at a time when only general guidelines concerning the desired combustion conditions for minimum NO_x generation were available from laboratory research. Methods of operating a boiler or necessary hardware modifications to provide those combustion conditions in a full-scale multiple-burner boiler were not clearly established. Analytical and experimental research in this area continue today. As is often the case in rapid technology development, the hardware and operating side of the industry was required to achieve certain goals using limited guidelines supplemented by the powerful method of "cut-and-try." A vital part of the iterative research and development process is the feedback to research of the results of this full-scale testing, both to provide evaluation of the initial guidelines developed in research as well as to provide a new source of information to guide further research.

The problem of describing and controlling the combined aerodynamics, reaction, and heat transfer within the reaction section of a full-scale combustor is highly complex and involves a large number of independent variables. A reasonable analysis of full-scale test results, then, requires a fairly large number of tests in which all of the significant variables are varied, even though the significance of the variables cannot be easily assessed before the results are analyzed. The stringent NO_x regulations imposed on electric utilities in the Los Angeles area have caused these utilities to try more NO_x reduction methods and to generate more data than elsewhere in the country. Certain common techniques have been established which significantly and reliably reduce NO_x emissions to 30 to 50 percent of the uncontrolled levels. In many areas of the country, these reductions are sufficient to meet any near-term regulations. Los Angeles area regulations, however, are sufficiently stringent that further reductions appear necessary. These further reductions require deeper understanding of control techniques.

Among the leaders in the analytical-empirical study of combustion modifications for NO_x reduction in utility boilers is the Los Angeles Department of Water and Power (LADWP), a municipally owned electric utility. Over the period 1969 to 1973, the LADWP conducted more than 500 full-scale multiple-burner boiler tests for the express purpose of developing optimum hardware configurations and operating conditions for minimum NO_x emissions compatible with low emissions of hydrocarbons (HC), carbon monoxide (CO), and smoke and with high plant efficiency and safe, stable boiler operation.

Initial NO_x reductions to 30 to 50 percent of uncontrolled levels appear to have been easily accomplished, with further reductions becoming progressively more difficult. This is indicated in Figure (1-1), which is a frequency plot of all of the LADWP NO_x data accumulated in this study. The figure shows that comparatively little testing was required to achieve a reduction in NO_x to 50 percent of initial levels, but that required to achieve another 50 percent reduction increased enormously. In fact, the increase in testing required for decreasing NO_x emissions appears to be exponential. This characteristic could result from (a) the exponential character of the NO_x generation rate with temperature, (b) the exponential decrease in understanding

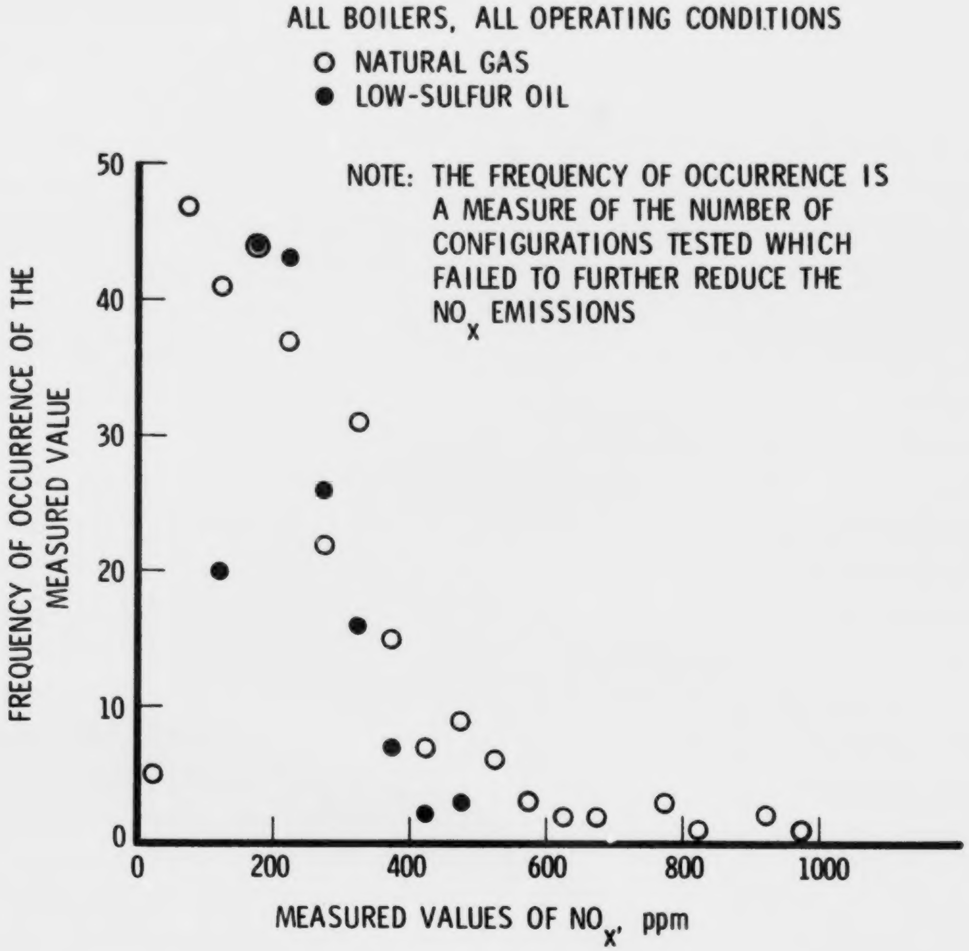


Figure 1-1. Frequency distribution of measured NO$_x$ data

of the remaining, minor sources of NO_x production at low NO_x emission levels, or (c) an asymptotic approach to real limits in minimum NO_x emissions with existing hardware and techniques.

Among the possible real limits to NO_x reduction appearing in this data are (a) excessive HC, smoke, or CO production and (b) combustion stability and flame stability problems, either of liftoff or of flames deep back in the burner, causing overheating. In the correlations of the effects of combustion modifications on NO_x emissions discussed in this report, some note is made of conditions which would appear to yield lower NO_x emissions but are prohibited from doing so because of high HC, smoke, or CO emissions. Approximately 20 percent of the effort in this study was devoted to the delineation and verification of the mechanism of observed combustion and flame instabilities (Section 3). Detailed stability analysis and solutions to these problems were deferred to a later study.

Complete data on hardware and operating conditions and the resulting measured emissions of NO_x, CO, oxygen (O_2), and carbon dioxide (CO_2) were obtained in nine face-fired boilers using natural gas and low-sulfur oil fuels. Test conditions yielding high emissions of HC or smoke were generally avoided; hence, all of the 485 tests analyzed in this study can be considered to be free of problems with these two emissions. The data resulting from these tests were sufficiently complete to be used in the analyses and are included in this report.

1.2 SUMMARY

The large number of independent variables which could have significant effects on NO_x emissions dictate, at least for an initial study such as this, a data analysis technique which can identify not only all of these potentially significant variables but, roughly, the proper form of these variables in relation to NO_x emissions. The analysis technique should also be capable of correlating large numbers of test conditions in which each of these variables are significantly varied. The study approach was to establish, first, a rough model of the processes of aerodynamic mixing, reaction, and cooling of the gases in the boiler and from that to develop a single equation which, if all of the input information were exact, would be capable of predicting the NO_x emissions. Since the information required to develop such a prediction equation is not well known, the equation was cast in the form of a series of linear terms, and the method of linear regression analysis was used to correlate the necessarily large samples of data from full-scale multiple-burner boilers. A total of 428 test conditions were used in these correlations, each involving more than 40 independent input variables specifying the hardware configurations and operating conditions. Obviously, a computer was necessarily employed to handle the input data, make necessary data conversions, calculate the values of the terms in the correlating equation, effect the linear regression analysis, and statistically evaluate the result.

The useful output of this study is not the resulting correlations themselves. Unlike many linear regression analyses, the correlation equation does not consist of a series of simple powers of the input variables. The calculation of the value of the parameter in each term of the correlation equation is much too complex to describe as a simple function of the independent variables, even including some tabular data read into the program. Use of the correlating equations to predict NO_x emissions requires the exact calculation procedure used in the correlations of this study.

The more useful output of this study lies in the insight gained concerning the effects of certain input variables on NO_x emissions, by study of the resulting correlations themselves and by the parametric exercise of these equations. Such insight can be generalized to indicate hardware and operating conditions for minimum NO_x emissions in many boilers and, in some cases, the levels of NO_x emissions under these minimum conditions. Such generalizations represent the important conclusions reached from detailed analyses of the data from 428 test conditions on 4 face-fired boiler types (8 boilers) with natural gas and low-sulfur oil fuels.

In general, all of the effects of combustion modifications on NO_x emissions appear roughly explainable by the equivalent air-fuel (A/F) ratio, temperature, and time history of the reactants as they flow through the aerodynamic mixing and reaction zones in the boiler and become subject to cooling by the boiler water walls. Further insight is gained from the effects of this history on a simple Zeldovich mechanism for NO_x generation. Since combustion reactions occur at the molecular level, the appropriate A/F ratio is the average molecular-scale mixed air-gaseous fuel (or vapor fuel in the case of liquid fuels) ratio. The effects of combustion modifications on NO_x emissions are discussed with respect to that history.

Similarly, the observed combusion instabilities appear to result from coupling of the air feed system with combustion in the boiler. One of the phenomena controlling this feed system coupled instability is related to the effect of partial combustion within the burners on the admittance (inverse of resistance) to air flow through these burners. This effect also strongly controls the distribution of combustion air between burners flowing both fuel and air (F+A) and those burners flowing air-only (Air), and any NO_x ports. NO_x ports are separate ports to introduce combustion air well downstream of (above) the burner flows. This combustion air maldistribution contributes to some of the observed flame instabilities. More specific conclusions drawn from this study form the bases for the following discussion.

1.2.1 Effects of Combustion Modifications on NO_x Emissions

In an uncontrolled boiler, the A/F ratios and temperatures in all parts of the boiler, for significant lengths of time, are at values which represent rates of NO_x generation close to the maximum possible for that boiler. Any combination of modifications which result in significant (a) changes in A/F ratio (either increase or decrease), (b) reduction in reaction product temperatures, or (c) reduction in the time spent by the reaction products under high NO_x generation conditions will almost inevitably result in a significant reduction in NO_x emissions. As a result, reductions to 30 to 50 percent of the uncontrolled NO_x emissions are relatively easy to accomplish. Reductions below those levels, however, require much more detailed understanding and control.

Combustion modification techniques for NO_x reduction which could be studied with the available data sample included (a) reduction in combustion air temperatures, (b) increased boiler cooling rates, (c) two-stage combustion using NO_x ports, and (d) burners-out-of-service (BOOS) (shutting off the fuel to some of the burners). Flue gas recirculation (FGR) into the primary flame zone could not be studied because FGR in the boilers in the data sample was introduced only from the bottom of the boiler. No significant effect of FGR introduced in this manner could be observed.

Reduction in the combustion air temperature reduces NO_x emissions but becomes decreasingly effective at the lower temperatures. Even a reduction to ambient temperatures represents a relatively small reduction in the peak reaction temperatures (about 10 percent). Depending on how such a reduction in combustion air temperature was accomplished, significant plant efficiency losses could result. In any case, NO_x emissions with oil fuels could not be reduced below that resulting from conversion of fuel bound nitrogen by this technique alone. In conjunction with two-stage combustion or BOOS techniques to reduce the conversion of bound nitrogen, combustion air temperature reduction might be effective in reaching lower than current NO_x levels, but plant efficiency would be decreased.

Increasing the cooling rate in the radiant section of the boiler has essentially the same effects of combustion air temperature reduction, except that the heat is always rejected to the working medium (water-walls), and the plant efficiency should not be compromised. Boiler modifications to increase this cooling rate, however, are extensive, and care would have to be taken to maintain sufficient bulk gas temperatures to the superheater tubes. In many practical cases, it appears that when the cooling rate (per unit length of the radiant section) becomes too great, FGR is introduced from the base of the boiler by the operator to counteract this excessive cooling and drive the hot gases more quickly up to the superheater tubes.

Two-stage combustion simply subtracts some of the combustion air from the burners, leaving the majority of the boiler combustion volume fuel-rich. The remaining air is added downstream after maximum cooling has occurred. The NO_x reductions by this method alone are generally limited (to levels which are still significant) by the NO_x generated when the remaining excess air is added.

The major effect of BOOS is the same as that of staged combustion. This technique is also limited in NO_x reduction to significant levels, unless great care is taken as to where and how much excess air is added to the reacting gases. Both the staged-combustion and BOOS techniques, however, can significantly reduce the conversion of bound nitrogen in oil fuels, leaving only the thermal NO_x as the problem. Neither the staged combustion nor the BOOS techniques necessarily result in significant plant efficiency losses, nor do they require major hardware modifications to implement.

Further insight into the effects of the above combustion modification techniques on NO_x emissions in full-scale multiple-burner boilers was obtained by direct study of the correlation equations and by parametric studies using these equations, with confirmation from data where available.

1.2.1.1 Correlation Equations

Insight into the effects of combinations of the above combustion modifications on NO_x emissions was obtained, first, by direct study of the average empirical values of the terms in the correlations and, secondly, by parametric exercise of these equations. The correlations contain both positive and negative terms (Section 2, Table 2-7). Therefore, insight into the potential for minimum NO_x production can be obtained by considering those hardware and operating conditions (Section 2, Table 2-4) which would maximize the dominant negative terms and minimize the dominant positive terms in the correlations. Two major observations from direct study of the correlations involved differences between natural gas and oil fuels and between large and small boilers. These differences were pursued further in the parametic studies.

1.2.1.1.1 Differences Between Gas and Oil Fuels

In the large boiler type of this study (H5/6) (Section 2, Table 2-1), which incorporates a large vertical array of burners (six rows high), the dominant terms in the correlations were those related to the configurations of (Air) and (F+A) burners in the burner array. Those related to bulk gas and NO_x port mixing zones were of lesser or indeterminant significance. In this large boiler type, the signs of the dominant burner configuration terms were exactly opposite for natural gas and oil fuels. From consideration of the signs of these dominant terms, minimum NO_x emissions with natural gas fuels in this large boiler type appeared to result when the total number of (Air) burners was small and the burners were located near the middle rows of the burner array. These same considerations indicated that with oil fuels in this large boiler type, minimum NO_x emissions appeared to result when the total number of (Air) burners was large and the burners were located in or near the bottom or top rows of the burner array. This somewhat surprising observation could not be generalized from direct study of the correlations alone. Neither could it be ascertained, at that point in the study, whether the conditions indicated for minimum NO_x emissions had actually been tested or whether those conditions represented possible new burner configurations capable of further significant NO_x reduction. Extensive parametric studies in conjunction with and guided by the above observations were necessary to achieve the final observations.

1.2.1.1.2 Differences Between Large and Small Boilers

In the study of the large boiler type incorporating a large vertical array of burners, the dominant terms in the correlating equations were those related to the configuration of (Air) and (F+A) burners in the burner array. In the smaller boilers incorporating a more limited vertical array of burners, the bulk gas and NO_x port terms were of approximately equal importance to the burner configuration terms. In all sizes of boilers, the signs of the burner configuration terms for gas fuels remained the same. With oil fuels, the signs of these terms tended to reverse as the size of the boiler decreased and to become similar to those for the gas fuels. The somewhat obvious generalization from this result is that the arrangement of (Air) and (F+A) burners in the array becomes less important to NO_x emissions as the size of the array approaches one (single burner). This result was significant in the progress of this study.

Laboratory testing of boilers involving the mixing, reaction, and heat transfer phenomena occurring in full-scale boilers with large numbers of burners would be prohibitively expensive. The most significant new insight possible from the study of data from full-scale boilers, then, concerns the effects on NO_x emissions of the interactions between burners in large burner arrays. Since the correlations of data from the small boilers in this data sample indicated a markedly reduced influence of burner configuration over that in the larger boiler type, the parametric studies of burner configuration effects were limited to the large boiler type (H5/6) alone. Conclusions reached from study of these effects in the large boiler type were evaluated for application to small boilers, using applicable small boiler data.

1.2.1.2 Parametric Studies

For reasons discussed in 1.2.1.1.2, the parametric studies were conducted using the correlation equations for natural gas and oil fuels in the large boiler type (H5/6). The effects of load (megawatt plant electrical output) variation on NO_x emissions are well known. Load variation, however, is not considered a desirable NO_x control technique not only because it limits the available plant capacity but it usually results in a significant loss in plant efficiency. Nevertheless, parameteric runs were made with load as the variable: (a) to check the accuracy of the multiple-variable correlations when used to predict the effects of single variables and (b) to evaluate the relative contributions to NO_x emissions of the combustion air temperature and total throughput flow variations which result from the load variations and more directly control NO_x emissions. Similarly, although combustion air temperature and boiler cooling rate control are not particularly desirable NO_x emission control techniques because of potentially significant plant efficiency losses and/or the major hardware modifications required, their effects on NO_x emissions were also evaluated in single variable parametric runs. No further effort was made in this study to evaluate the effects of these variables. Efforts were, instead, concentrated in the potentially more productive areas concerning the effects of excess air, NO_x ports, and burner configurations.

1.2.1.2.1 Load, Combustion, Air Temperature, and Boiler Cooling Rate Effects

Reduction in plant electrical load is accomplished by reducing the total fuel and air flow through the boiler, essentially at a constant A/F ratio. This reduction results in greater total cooling of the combustion gases and, through the air preheater, a reduction in combustion air temperature. Empirical correlations of both throughput flow and combustion air temperature with the overall plant load were derived from the data. Parameteric variation of load, then, resulted in the simultaneous parametric variation of both of these variables. Comparison of the calculated and measured NO_x emissions with load variation showed reasonable agreement with natural gas fuel and excellent agreement with oil fuels. In both cases, reducing the load reduced NO_x emissions. Calculated NO_x emissions at half-load were about 73 and 70 percent of those at full load with gas and oil fuels, respectively. Separate parametric runs to evaluate the relative contributions of throughput flow and combustion air temperature over the ranges dictated by load variations, as single variables, indicated some surprisingly large differences with gas fuels and relatively small differences with oil fuels. Since no data were available to evaluate these separate calculated effects, these differences were not pursued further.

Combustion air temperatures were further varied over a wide range, involving extrapolations by more than a factor of six beyond the temperature data in the correlations (to ambient temperatures), with full-load throughput flow. Although calculations involving such large extrapolations may or may not be valid, results indicate that

NO_x emissions with combustion air temperatures reduced to ambient are about 36 and 53 percent with gas and oil fuels, respectively, of those at the full-load temperature. With the same reservations resulting from large extrapolations, it would appear that the NO_x emissions at ambient temperatures with gas fuels are still decreasing with decreasing temperature, while those with oil fuels appear to be asymptotically approaching a value corresponding to the conversion of the fuel-bound nitrogen (no NO_x emissions from thermal fixation mechanisms).

Extrapolations by a factor of about 2.6 in the boiler cooling rate (reduction in combustion product temperatures with time) showed that the NO_x emissions with gas fuels rapidly approached zero, while those with oil fuels again approached a value resulting from conversion of fuel-bound nitrogen alone. Both of these results and those for combustion air temperature variations are in agreement with theoretical thermal and fuel-bound nitrogen conversion mechanisms for the formation of NO_x emissions. Extrapolations much beyond 2.6 times the data range in the boiler cooling rates resulted in unrealistic NO_x emission variations.

1.2.1.2.2 Excess Air, NO_x Port, and Burner Configuration Effects

Boiler operation with reduced excess air is often recommended as a significant NO_x reduction technique, particularly since it appears to increase plant efficiency. There was no evidence of significant effects of excess air variation on NO_x emissions in the data of this study. Parametric variations of excess air, in fact, showed that NO_x emissions with gas fuels increased slightly with decreased excess air. Those with oil fuels did decrease with decreasing excess air, but again only slightly. Although the available applicable data were widely scattered, it appeared to confirm these trends. The magnitudes of the calculated and measured NO_x values were in good agreement in both cases. These results are interpreted to indicate that, at normal values of excess air, thermally generated NO_x increases as excess air is reduced toward stoichiometric but conversion of fuel-bound nitrogen always decreases with decreasing excess air. With natural gas fuels, there is no fuel-bound nitrogen; therefore, NO_x emissions are thermally generated and will increase with decreasing excess air as long as that excess air is above zero. With the oil fuels of this data sample, containing very little bound nitrogen, the tradeoff between increasing thermally generated NO_x and decreasing conversion of fuel-bound nitrogen with decreasing excess air results in a slight net decrease in NO_x emissions. Fuels containing larger concentrations of bound nitrogen (such as coal) should always exhibit the expected strong trend toward decreasing NO_x emissions with decreasing excess air. Because the variation of NO_x emissions with excess air with the fuels of this study is so small (±7 to 10 percent over the practical range of excess air), no further effort was made to study this variable.

Parametric variations of the fraction of combustion air flowing through NO_x ports were conducted with extrapolations to about 2.4 times the data range. Again, confirmation of the calculated values with appropriate data was reasonable with gas fuels and excellent with oil fuels. With both fuels, the NO_x emission levels asymptotically approached a limiting value as the fraction of combustion air through the NO_x ports increased. With all burners operating on (F+A) and 3 percent O_2, these limiting values were 32 and 52 percent, for gas and oil, respectively, of the values with NO_x ports closed. Since the air-fuel ratio in the burner region of the boiler would be uniformly very low, the NO_x emissions with large fractions of combustion air flowing through the NO_x ports are interpreted to be generated in, and downstream of, the NO_x port mixing zones. Thus, although the effect of NO_x ports in reducing overall NO_x emissions with all burners operating

(F+A) is dramatic, this technique alone is limited to NO_x levels which are still quite significant. Further, when used in conjunction with BOOS (a practical substitute for NO_x ports), further combustion air diverted through NO_x ports may have very little effect on further reduction in NO_x emissions and, in some cases, could even increase these emissions.

The bulk of the parametric studies of NO_x emissions in the large boiler type were concentrated on the effects of various numbers and configurations of (Air) and (F+A) burners in the burner array. Various vertical and horizontal combinations of four and eight (Air) burners were evaluated, generally, with other input variables held constant. In some cases, fixed configurations were evaluated with NO_x port air flow and combustion air temperatures as the variables. Not all combinations with up to 8 of the 24 (Air) burners were evaluated since more than a million combinations are possible.

Although a number of effects were observed, the two most significant variations involved the number of (Air) burners and their vertical location (as a group) in the burner array. In general, the parametric calculations showed that configurations involving only one to four (Air) burners yielded minimum (in fact, negative) values of NO_x emissions with gas fuels, if these (Air) burners were located in the third to fifth row from the bottom of this six-row array. Unfortunately, little or no test data involving one through seven (Air) burners were in the data sample, so this possible minimum could not be confirmed. Configurations involving no (Air) burners or eight (Air) burners, no matter how they were arranged, yielded larger values of NO_x emissions with gas fuels. The minimum NO_x emission configuration indicated by the available gas-fired test data with eight (Air) burners was with the eight (Air) burners located as high as possible in the burner array with NO_x ports open.

As indicated by direct observation of the dominant terms in the correlation equations, the results of parametric studies of burner configurations with oil fuels in the large boiler type indicated almost directly opposite configurations for minimum NO_x emissions from those with gas fuels. Instead of a small number of (Air) burners located in the middle rows of the burner array as indicated with gas fuels, the parametric studies with the oil fuel correlation indicated that minimum NO_x emissions should be achieved with a larger number of (Air) burners (eight in this study) located at either the top or bottom of the burner array, with the bottom location yielding the lower NO_x emissions. Attempted confirmation with applicable data indicated that NO_x emissions monotonically decreased with (Air) burners located lower in the burner array. Configurations with (Air) burners located in the bottom row were not in the data sample. Minimum NO_x emissions obtainable with existing hardware with these oil fuels, however, appear to be most closely approached in the data sample with four of the eight (Air) burners located in the second row from the bottom of the array.

Evaluation of the results of the parametric studies and data confirmation as they might apply to the smaller boilers indicated the same general locations for (Air) burners to achieve minimum NO_x emissions with both fuels (i.e., at the top for gas fuels and at the bottom for oil fuels). The effects of (Air) burner locations, however, were much less significant than in the large boiler type.

1.2.1.3 General Considerations for Minimizing NO_x Emissions

The results discussed in Sections 1.2.1.1 and 1.2.1.2 were interpreted in the light of the general mechanisms for the formation of NO_x from thermal fixation and fuel-bound nitrogen conversion and the probable A/F ratio temperature and time history of the reacting gases. In general, thermally generated NO_x can be minimized by maintaining the molecular-scale, mixed A/F ratio either fuel-rich or fuel-lean. Conversion of fuel-bound nitrogen can be minimized only by maintaining the A/F ratio in the burner area of the boiler fuel-rich. In each case, the amount of time spent by the reacting gas at A/F ratios near stoichiometric must be minimized to minimize thermally-generated NO_x. The major mixing of the reacting gases from any given burner with those from the burners below occurs when the burner gases encounter the bulk gases. The molecular-scale, mixed A/F (gas or vapor) ratio in the burner gases and the bulk gases as this mixing begins determines whether the A/F ratio of the burner gases must pass through stoichiometric during the subsequent mixing process and, therefore, what the relative A/F ratios of the burner and bulk gases should be at the vertical level of that burner to minimize net NO_x emissions.

With the current hardware configurations of the boilers of this study, certain combinations of operating conditions or combustion modifications yield the minimum NO_x emissions observed in the data. In one case, the general considerations derived from this study indicate that further reduction may be possible with a combination of operating conditions which were not in the data sample. These same general considerations, however, indicate that over the longer range view, when new power plants are built or when significant hardware modifications might be implemented on existing plants, totally different combinations of operating conditions would yield minimum NO_x emissions. These levels, with the new or modified hardware, are expected to be significantly lower than those obtainable with current hardware. Conclusions applicable to current hardware are discussed in 1.2.1.4 and those applicable to the longer range in 1.2.1.5.

1.2.1.4 Minimum NO_x Emission in Current Hardware

Two major differences in the boilers of this study significantly affect the operating conditions for minimum NO_x emissions.

These are the so-called large boilers, in which a large number of burners (24) are distributed vertically in six rows, and the small boilers, in which the number of rows of burners is less than five. Minimum NO_x emissions in the hardware of this study are discussed separately with respect to the large and small boilers, with both gas and oil fuels in each.

1.2.1.4.1 Large Boilers

Final results indicate that combinations of combustion modifications which yielded the minimum NO_x emissions observed in the gas-fired test data of this study are predominantly determined by the fact that air-gas fuel mixing is relatively rapid. Average molecular-scale, mixed A/F ratios equal to the burner input A/F ratio are reached before the burner flows begin to mix with the bulk gas flow. This indicates that the bulk gas A/F ratio should be near that of the burner.

Such configurations result in current hardware when (Air) burners are located high in the burner array or when NO_x ports are open. Average A/F ratios must eventually cross stoichiometric to reach the overall boiler excess air condition, when the excess air is finally added to the burner flows high in the boiler, but this is accomplished only after maximum cooling of the gases has occurred. All of the reacting gases (burner and bulk) in the burner region of the boiler are at A/F ratios well below stoichiometric.

The above is supported by the observation that, with eight (Air) burners in the burner array, minimum NO_x emissions of 197 ppm were achieved (in the data sample) in the large boiler type, fired at full load with gas guel and with the (Air) burners located as high as possible in the boiler and NO_x ports open.

The large boiler parametric studies also indicated that a possible NO_x minimum even lower than this might be achieved by locating just a few (Air) burners in the fourth or fifth rows from the bottom of this six-row burner array. This observation would also be compatible with the above observations if it were assumed that the air/gas-fuel mixing to molecular-scale, although very fast, required a finite time and distance into the boiler to occur. As the bulk gases grow in volume and spread across the boiler cross section, as they flow up the radiant section, at some level the burner gases would not have time to complete the necessary internal mixing before they encounter forced mixing with the spreading bulk gases. This would be the appropriate level, then, to introduce some (Air) burners to convert the fuel-rich bulk gases from below to air-rich gases. Such a configuration was not represented in the data.

Combinations of combustion modifications which yield the minimum NO_x emission observed in the data of this study when firing low-sulfur oil fuel, with 0.24 percent by weight bound nitrogen, are predominatly determined by the fact that the rate of mixing of the air-vapor fuel is very slow. This mixing rate is controlled by the vaporization rate of the liquid fuel rather than by the air turbulence. As a result, the average molecular-scale mixed air-vapor fuel ratio cannot reach that of the burner overall air-liquid fuel ratio before significant mixing with the bulk gases begins. This indicates that the bulk gases should be maintained air-rich to keep this average A/F ratio from ever crossing stoichiometric and to minimize thermally-generated NO_x. Unfortunately, with oil fuels, this type of A/F ratio tailoring results in maximum conversion of the fuel bound nitrogen. Thus, with oil fuels, two possible minimum NO_x conditions result: one with minimum thermal NO_x but maximum fuel NO_x (the latter case) and one with the reverse resulting from fuel-rich burners and fuel-rich bulk gases. In boilers burning oil fuels with very low bound-nitrogen content and high thermal NO_x formation rates, the lower minimum may be the air-rich bulk gases case, simply accepting the maximum conversion of the bound nitrogen for the boiler excess air level. This is the case with all of the boilers in the sample of this study using the low-sulfur fuel containing 0.24 percent by weight bound nitrogen. This case is implemented in the existing hardware by locating a few (Air) burners low or at the bottom of the burner array (and no NO_x ports). The NO_x minima achieved in the data are approximately 220 ppm, at 3 percent O_2, in good agreement with conversion efficiencies of bound nitrogen from the literature. No significant problems of excessive CO, HC, or smoke, combustion or flame stability, or losses in plant efficiency were observed under conditions sufficient to reach this minimum. In other boilers, with lower combustion air temperatures or higher cooling rates, burning oil fuels containing more nitrogen, the lower of the two NO_x minima could be the opposite of that observed in this study.

1.2.1.4.2 Small Boilers

Final results indicate that the effects of (Air) burner locations in the burner array are much less significant in small boilers involving limited numbers of burners and limited vertical distribution of the burner array. In a boiler with 12 burners arranged in a configuration of 4 burner columns wide and 3 burner rows high, filling 1 row with (Air) burners leaves only 2 rows of (F+A) burners. Thus, there is little room for definition of top, middle, or bottom rows. The whole boiler begins to take on the characteristic of a single-burner boiler, and the burner gases begin to become indistinguishable from the bulk gases. Under these conditions, it might be expected that only the general case of two-stage combustion would have any significant effect on NO_x emissions. Two-stage combustion could be accomplished either by locating (Air) burners in the top row of the burner array and/or with open NO_x ports) (fuel-rich to fuel-lean staging) or by locating the

(Air) burners in the bottom row with NO_x ports closed (fuel-lean to fuel-rich staging).

These conclusions are supported by the observations that minimum NO_x emissions in small boilers, when fired with natural gas fuel, were achieved with two-stage combustion by the use of NO_x ports or by locating a few (Air) burners in the top row of the burner array. NO_x emission levels, with 3 percent O_2 (equivalent excess air) of 110 to 140 ppm were achieved in the small boilers in the sample studied with no undesirable emissions of CO, HC, or smoke, with no combustion or flame instabilities, and with no significant losses in plant efficiency. The small boiler data with oil fuels also supports these observations. Minimum NO_x emissions were achieved when the (Air) burners were located lower in the array, as in the large boiler type. Minimum NO_x emissions observed in this data were 178 to 208 ppm, again only slightly lower than the value calculated for full conversion of the fuel-bound nitrogen at the boiler excess-air condition. No significant problems of excessive CO, HC, or smoke, combustion or flame stability, or significant losses in plant efficiency were observed under conditions sufficient to reach this minimum.

1.2.1.5 Longer Range NO_x Emission Reduction

Since natural gas fuels contain no fuel-bound nitrogen, minimum NO_x emissions can be attained by maintaining the A/F ratio in the radiant section of the boiler either fuel-rich or fuel-lean to minimize thermally generated NO_x. The overall boiler, however, is always maintained slightly fuel-lean to minimize CO, HC, and smoke emissions. Thus, if the burner section is maintained fuel-rich, the average molecular-scale mixed A/F ratio must cross stoichiometric at lease twice in the reacting section of the boiler.

It appears that low NO_x emissions can be achieved in gas-fired boilers by a combustion modification technique opposite to that which results in the minimum with existing hardware. This technique would involve operating the burners and the resulting bulk gases slightly more lean (air-rich) than the overall boiler A/F ratio by reducing the fuel flow to the burners and adding the remaining fuel well downstream of the burners in fuel NO_x ports. This scheme would avoid the necessity for the average molecular-scale mixed A/F ratio to ever cross stoichiometric. This combustion modification can yield very low NO_x emissions because of the absence of fuel-bound nitrogen in the natural gas fuel. No inherent problems of excessive CO, HC, or smoke emissions, of combustion or flame instability, or significant losses in plant efficiency are apparent in this configuration.

Further significant reduction of NO_x emissions with bound nitrogen-containing oil fuels requires that the conversion of the bound nitrogen to NO_x be minimized. At the moment, the only way to accomplish this is by initially reacting the fuel in a fuel-rich air-vapor fuel environment. This is generally impossible, and thermally generated NO_x can be large, if the fuel is slowly bled into the surrounding air stream as it vaporizes. This suggests that very fine atomization or prevaporization of the oil is a necessary prerequisite. A general approach to the ultimate minimum NO_x emissions with oil fuels, then, appears to involve very fine oil atomization, strong fine-scale turbulence, and use of NO_x ports or (Air) burners located high in the burner array. No inherent problems of excessive CO, HC, or smoke emissions or losses of plant efficiency are apparent in this configuration. Since the finely atomized, rapidly mixed oil fuel combustion would behave somewhat like natural gas combustion, care would have to be taken to avoid combustion or flame stability problems.

1.2.2 Combustion and Flame Stability

Application of a general stability criterion for feed system coupled modes derived in the liquid rocket industry indicates that this type of combustion instability is probable in boilers coupled with the air feed system. The resistance to air flow through the burners from the windbox to the furnace is relatively small. As a result, the air flow rates through the burners are only weakly controlled. Small perturbations in the local pressure in the furnace can easily represent large perturbations in the pressure drop across the burners and, therefore, in the air flow through the burners. This is the definition of a high dynamic response feed system.

The small pressure drop across the burners also allows any partial reaction in the diffusion flame within the burner to dominate and greatly increase the resistance to air flow through the burner. When other nonburning flow paths are available for air flow, such as NO_x ports (in two-stage combustion) or (Air) burners (in the BOOS technique), the increased resistance to air flow in the (F+A) burners causes an unexpectedly large diversion of air flow to these nonburning paths. This effect is nonlinear and is compounded by this diversion, causing even further reduction in the (F+A) burners. The resulting large imbalance in air flow distribution between the burning and nonburning paths has strong effects on both steady-state NO_x emissions as well as on the dynamic response of the air feed system to furnace pressure perturbations and air feed system coupled combustion stability.

The available data indicate that when about 75 percent of the burners in the burner array or equivalent NO_x port flow area are configured for air flow only, the A/F ratio in the remaining (F+A) gas-fired burners drops below or near the fuel-rich premixed flammable limit for air-natural gas flames. Since the flames in the (F+A) burners are not well-mixed (a diffusion flame), the flame does not extinguish in the pilot zone in the burner but the reaction may not go to completion as molecular-scale mixing is approached. Under these same conditions, the nonlinear effect of the flame in the burner begins to strongly amplify the air feed system response, leading to air feed system coupled combustion instability.

Records of visual observations of gas-fired burner flames under these operating conditions indicate all of the poorly anchored, ragged characteristics typical of operation near a premixed flammable limit. The available data on observed gas-fired combustion instabilities also correlate well with this operating condition. Flame stability problems of the type where the flame retreats deep into the burner, causing burner and register overheating, are a further result of these operating conditions.

Flame liftoff appears to be simply the opposite case. If a burner gas spud is designed to limit mixing within the burner to minimize the flame deep in the burner, then, under conditions of higher air velocity through the burner, the flame can rather easily be blown off the pilot zone and lift off of the burner.

All of the combustion and flame stability problems discussed occur in gas firing. Since oil fuels do not need to be anchored by a pilot zone in the burner and since they have not begun significant vaporization within the burner, the problems associated with the effects of partial reaction within the burner are usually not significant. The approach to ultimate reduction of NO_x emissions with oil fuels, i.e., the finely atomized rapidly mixed oil combustion discussed in Section 1.2.1, suggests that these oil flames could provide all of the conditions discussed for gas flames which yield combustion and flame instabilities. Solutions to such problems are possible, however, and involve proper design of the oil gun spray with respect to the air flow profile through the burners. More detailed steady-state and dynamic analysis than that reported here is necessary to assure trouble-free operation. Similar problems could also occur if and when significant quantities of low-Btu gaseous fuels are fired in utility boilers.

SECTION 2

EFFECTS OF COMBUSTION MODIFICATIONS ON NO_x EMISSIONS

The purpose of conducting this study on large quantities of NO_x emissions data from operational multiple-burner utility boilers was to gain some insight into the fundamental combustion processes occurring in boilers as they affect NO_x emissions. Although a multiple regression analysis technique was used in the analysis, there was no intention to develop a universal correlation equation which could be used to predict NO_x emissions for any boiler simply by inserting the hardware and operating conditions of that boiler into these equations.

A large amount of raw data was accumulated during the course of this study from the records of the LADWP on NO_x emissions and related hardware and operating conditions. Nearly all of the fundamental combustion processes pertaining to NO_x emission reduction in full-scale multiple-burner utility boilers are represented in that data.

This section discusses the approach taken in the analysis of the LADWP data, observations from the correlations, parametric studies of the correlations, applications of combustion modifications for NO_x control, and estimations of NO_x minima for existing and future hardware.

2.1 DATA ANALYSIS APPROACH

The approach taken in analyzing the data was to (a) assemble a rough model of NO_x generation in a large multiple-burner utility boiler, using generally accepted principles; (b) use that model to generate a single equation which, if all of our input knowledge were correct and accurate, would directly predict NO_x emissions; (c) use that equation to correlate the data and correct for inadequacies in the input assumptions; and finally (d) analyze the resulting correlation equations to determine what these correlations indicate about the areas of poor understanding. This procedure is little different from that generally followed by engineers to obtain an understanding of the variations in some parameter of interest. The principal difference here is that a fairly large number of independent variables are known to affect NO_x emissions. This dictates that a fairly complicated model be established in order that each of these variables be included in their approximately correct form and with their approximately correct relationship to each other and to the NO_x emissions. Each of the steps involved in this procedure are discussed.

2.1.1 The NO_x Model

Several important variables relating to NO_x emissions from a large multiple-burner boiler describe the air flow through NO_x ports and take into account the geometric relations between burners flowing (F+A) and those flowing (Air). Experimental data involving these variables can come only from the large multiple-burner boilers themselves. Therefore, it was considered of primary importance to establish a model which included the effects of these variables as improved understanding would most likely come from this area.

The model, shown schematically in Figures 2-1 and 2-2, was established for the largest and most complex of the boilers studied. Figure 2-1 shows a series of fixed mixing zones in the horizontal plane at the lowest furnace level. The effects of horizontally adjacent and opposite burner flows on each other are accounted for by mixing in the adjacent and opposite mixing zones, and the effects of all flows in a

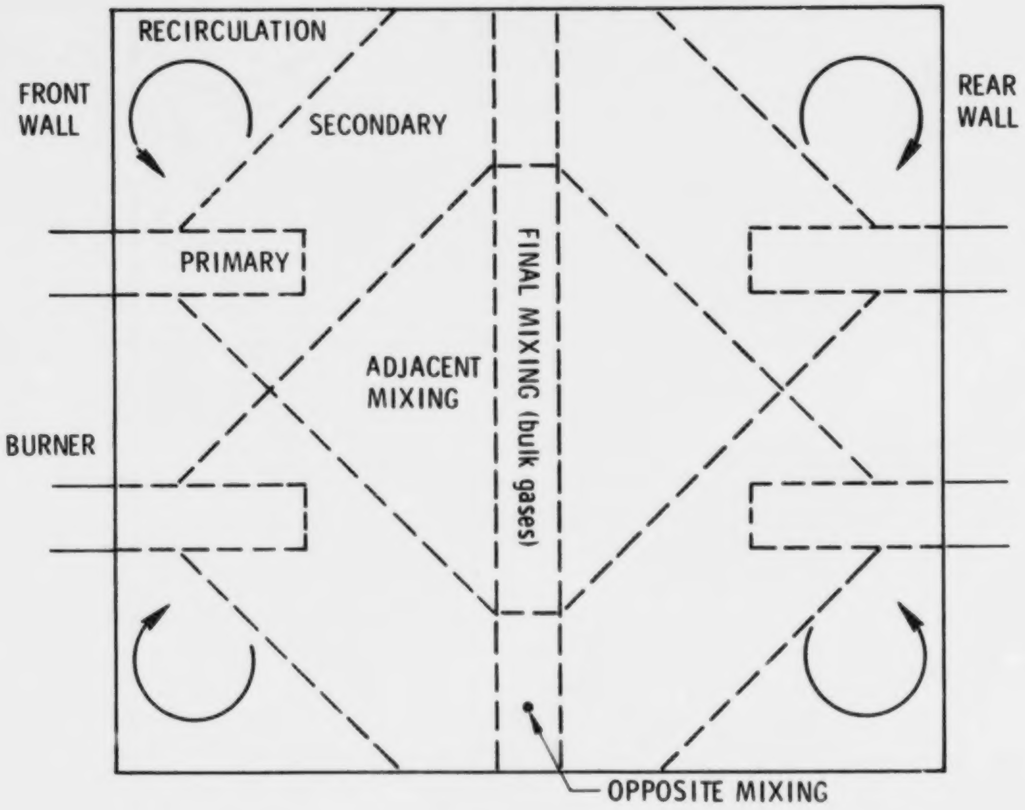

RECIRCULATION
FRONT WALL
SECONDARY
REAR WALL
PRIMARY
FINAL MIXING (bulk gases)
ADJACENT MIXING
BURNER
OPPOSITE MIXING

Figure 2-1. Schematic of mixing zone model--horizontal section at lowest burner level

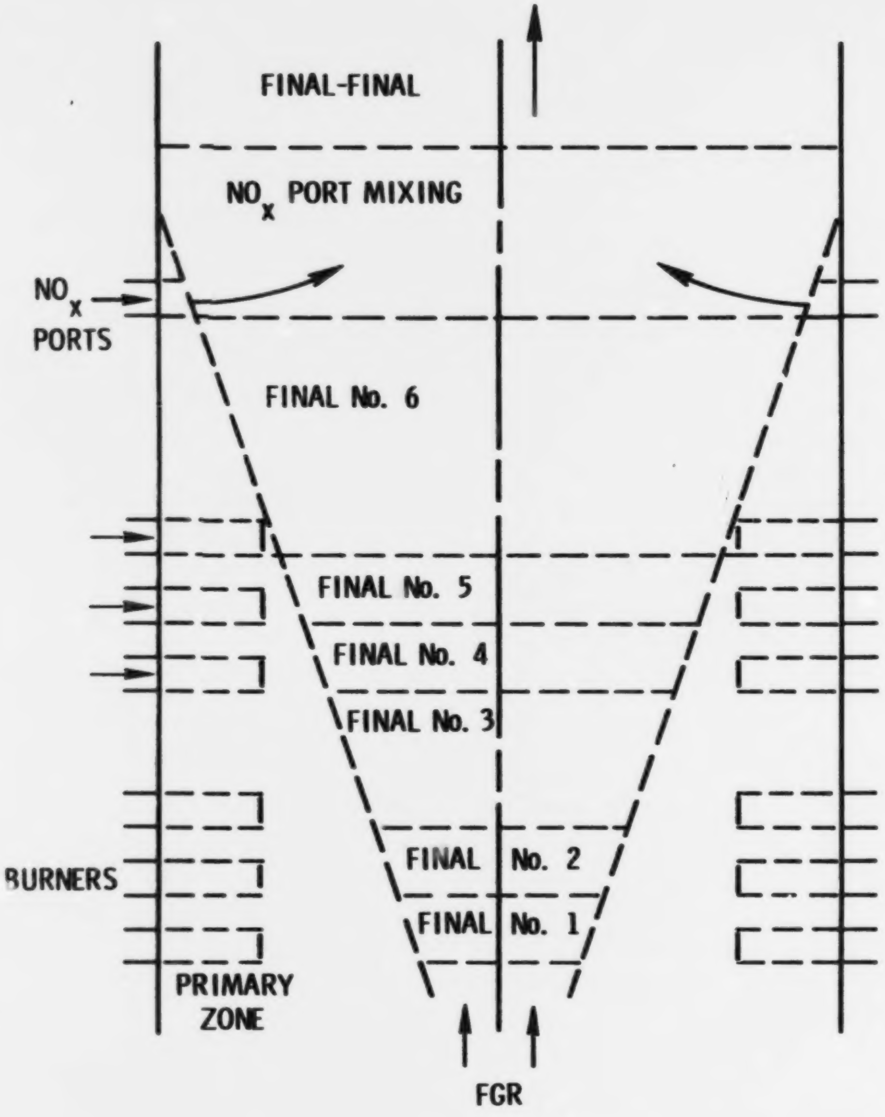
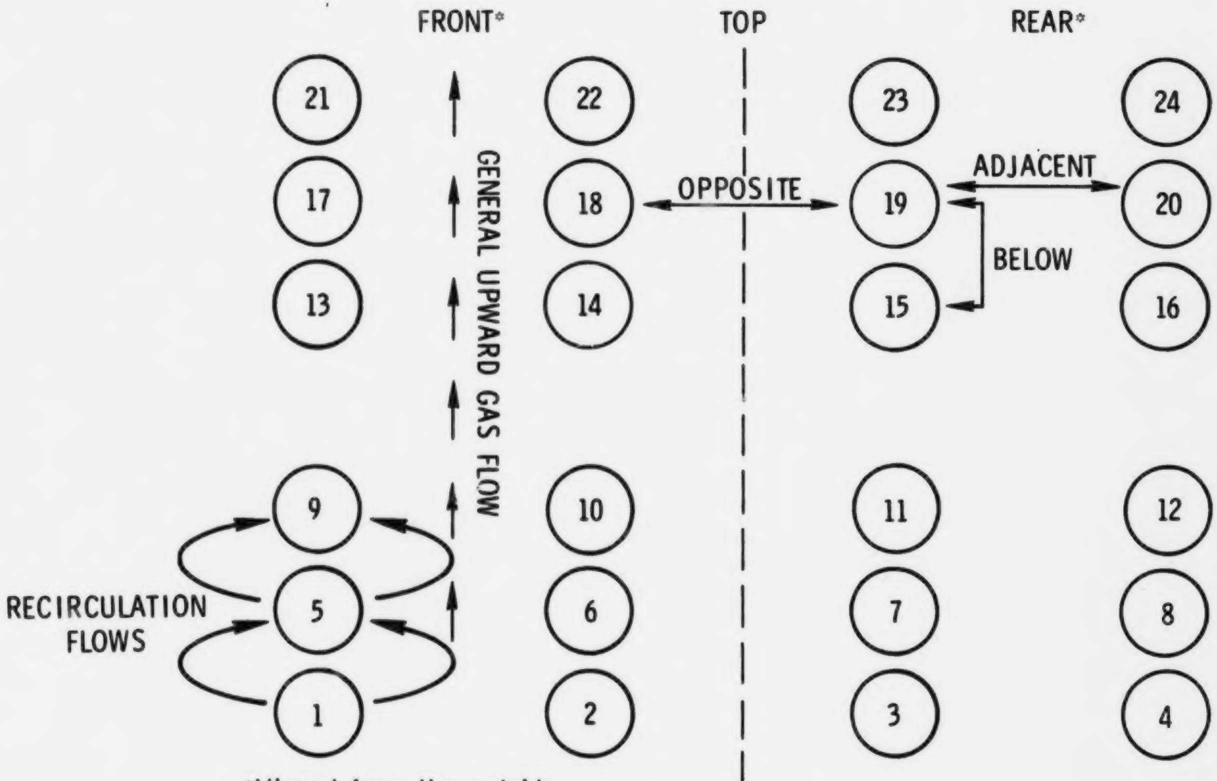

FINAL-FINAL
NO_x PORT MIXING
NO_x
PORTS
FINAL No. 6
FINAL No. 5
FINAL No. 4
FINAL No. 3
BURNERS
FINAL No. 2
FINAL No. 1
PRIMARY ZONE
FGR

Figure 2-2. Schematic of mixing zone model--vertical section

given furnace level are accounted for by the bulk gas mixing zones. Figure 2-2 shows the assumed spreading of the bulk gases as more burner flows are fed in and the vertical level increases. Two effects of the orientation of burners in the vertical level are accounted for (a) by the mixing of burner flows at a given level in the bulk gases with all of the flows from the burners below that level and (b) by the prevention or reduction of adjacent, opposite, and secondary mixing at a given level by the spreading bulk gases. Figures 2-1 and 2-3 show the assumed recirculation of part of the primary flow from one burner back toward the furnace firing face and upward to join the primary flow from the next higher level burner. This recirculation flow accounts for the effect of the flow from one burner on the burner flow immediately above it at all levels. Figure 2-3 shows the definition of burners adjacent, opposite, and below a given burner.

Figures 2-1 and 2-2 also show the approximate geometries of these various mixing zones. These zones are assumed fixed in space in a given furnace. The individual flows from each burner are assumed to flow through a larger or smaller number of these zones, in series, on the way to the NO_x port mixing zone. Through the NO_x port zone and beyond, all flows are assumed to be in the furnace, and the total flow and the A/F ratio are that of the overall furnace. As the flows pass from one zone to the other, the average flow velocity, A/F ratio, and equilibrium reaction products of the zone are assumed to be instantly established. The resulting mixture then flows uniformly through the zone.

Such a picture of the flow and mixing from multiple burners in a large boiler is not unreasonable. In any case, it does provide a rough framework on which a rough NO_x prediction equation can be established. This equation will include, among others, variables that account for the orientation of (F+A) and (Air) burners, horizontally adjacent and opposite and vertically adjacent, and for the vertical level


FRONT*
TOP
REAR*
21
22
23
24
17
18
19
20
13
14
15
16
9
10
11
12
5
6
7
8
1
2
3
4
GENERAL UPWARD GAS FLOW
OPPOSITE
ADJACENT
BELOW
RECIRCULATION FLOWS

*Viewed from the outside

Figure 2-3. Mixing zone model--definition of burner configurations

of the individual burners. Greater sophistication in modeling than this is not considered necessary for the purposes of this study. Further details on the geometry of these zones are described in Appendix A.

2.1.2 The General Correlation Equation

The correlation equation used in this study was developed, essentially, by tracking the flows from the individual burners through the various mixing zones to the top of the furnace (the end of the radiant section). In each mixing zone, the increment of NO formed in that zone was calculated, and the total NO emissions from the boiler was the sum of those increments. Fundamental to this approach is the assumption that NO_x levels are always well below equilibrium, and therefore the NO_x destruction rate is negligible.

The NO_x formation rate in each zone was calculated from

$$d[NO]/dt = (2.4 \times 10^{12})[N_2][O_2]^{1/2}\exp\left(-\frac{67,900}{T}\right) \qquad (2\text{-}1)$$

where T is equal to degrees Kelvin. Equation (2-1) was taken from Ref. 2-1 and was modified by assuming a negligible rate of NO decomposition and by conversion of the concentration terms [NO], $[N_2]$, and $[O_2]$ to mole fractions. Equation (2-1) is based on a Zeldovich mechanism of NO formation and assumes that oxygen atoms are in thermal equilibrium with oxygen molecules. This assumption is truly valid only for fuel-lean mixtures. Oxygen atom concentration is apparently somewhat higher than equilibrium under fuel-rich conditions. Equation (2-1) describes the formation only of thermal nitrogen and contributes nothing to the understanding of the conversion of fuel-bound nitrogen to NO. In view of the current ill-defined knowledge of the kinetics of fuel-rich HC combustion processes and of bound-nitrogen conversion, Eq. (2-1) was accepted as a first-order approximation of the formation rate of thermal nitrogen over the full range of A/F ratios. A separate term was included in the correlation equation to account for bound-nitrogen conversion, consisting only of a calculation of that NO which would be formed from the fuel-bound nitrogen if there were 100 percent conversion. It was left to the correlation to determine a coefficient for this term which might, at least, represent an average bound-nitrogen conversion efficiency for the data sample.

Two major problems in any attempt to model a complex aerodynamic mixing, reaction, and heat transfer process such as occurs in the radiant section of a large multiple-burner boiler are the determination of the chemical species and the temperature at every point in the volume. These inputs are important for each mixing zone in the furnace and establish the inputs to Eq. (2-1). These, however, are exactly the unknown inputs which might be at least partially explained by correlation of a large amount of data such as in this study.

Major assumptions made in this area in developing the correlation equation were:

a. Air and fuel, either gas or oil fuels, leave the burners in a completely mixed gaseous state.

b. Equilibrium combustion products and temperatures are maintained as subsequent mixing occurs in downstream mixing zones (shifting equilibrium).

c. The cooling rate of the gases is a constant function of time only.

The first assumption, of course, is not true. Even in the case of gas fuels, the flame issuing from the burners is a diffusion flame, with mixing to finer scale levels and further reaction continuing well into the primary mixing zone and beyond. Detailed analysis of the completeness of the gas flame reaction within the burner, discussed at length in Section 3 indicates that 20 to 30 percent of the gas flame combustion has occurred before the flame leaves the burner. This assumption is clearly not true for oil flames. The majority of the oil fuel leaving the burner is still in the liquid state, and the A/F vapor ratio is very large. The oil fuel must first vaporize, and subsequent reaction depends on the local A/F ratio surrounding the liquid droplets and the rate of further mixing with more distant air. Thus, the actual average A/F ratio existing in any mixing zone, on a molecular scale, depends not only on the gross mixing, which the rough model attempts to describe, but also on the breakdown of the gross-scale mixing into finer scale mixing, eventually approaching molecular scale. The NO reaction rate of Eq. (2-1) is based on the reaction product specie concentrations and temperatures on a molecular scale. An attempt to include all of these turbulent mixing phenomena in the rough model is clearly beyond the scope of this study.

Instead, assumption (a) was made, with the clear recognition of its inadequacy. Figures 2-1 and 2-2, however, show that certain of the mixing zones, which are represented in the correlation equation by individual terms, are close to the burner exit (primary zones) and some, such as the bulk gas zones, are farther away in both space and time. The data correlation can shed some light on both the error in assumption (a) and on the mixing processes actually occurring, by defining those zones which are and are not significant to the overall NO_x formation. If, for example, the data correlation shows that the primary and recirculation zones dominate the variations in NO formation, then it can be assumed that the assumption is approximately correct and that the bulk of the gases in those zones, on a molecular scale, are at or are passing through A/F ratios near stoichiometric. Critical to the arrangement of (F+A) burners and (Air) burners in the array is the relationship between gross-scale and molecular-scale mixing in the full-size boiler.

Assumption (b) is a reasonable one and will be discussed no further here.

Assumption (c), on the cooling rate of the gases in the various zones, is not necessarily a good one. It seems reasonable that the cooling rate in zones well removed from the water walls, where heat loss is by radiation to the walls, might asymptotically approach a constant. The cooling rate in the recirculation zones, however, where heat loss could be dominated by convective heat transfer, may be considerably higher than in the other zones. Several attempts were made to establish a spatial distribution of cooling rates throughout the furnace, using water wall heat flux profiles supplied by the utility. Indications were, at least in that section of the furnace up through the NO_x port mixing zone, that a constant cooling rate with time alone was a reasonable approximation. The data were too limited, however, to confirm this indication. Because of the limited scope of this study, a constant rate was incorporated. The danger in this simple assumption is that the temperature enters into Eq. (2-1) in the argument of the exponential term. A linear regression analysis might not be able to compensate for a large error in this nonlinear term. Assumption (a) also strongly affects the calculated temperature in a given zone, at least in the early mixing zones where it is known to be invalid. Both of these potential errors had to be accepted, however. It was expected that, at worst, significant errors due to these two assumptions would be reflected in an inability to obtain good correlation of the data.

Further details on the development of the correlation equation are described in Appendix A. Appendix B discusses the fuel analyses and the equilibrium combustion calculations made with these fuels.

2.1.3 Application of the Correlation Equation

The approach to analysis of the data, involving the development of a rough NO prediction equation from a rough model of the combustion processes occurring throughout the furnace, was intended to maximize the probability that all of the significant independent variables affecting NO_x emissions were included in the correlation equation, in the approximately correct form and with the approximately correct relationship to the NO_x emissions. For example, the rough analysis indicates (a) that the initial combustion air and fuel temperatures, the equilibrium temperature rise due to reaction at the A/F ratio of a given zone, and the temperature decrease due to cooling enroute to the zone are all significant independent variables, (b) that they should be related in the form of a sum to establish an estimate of the average temperature in the zone, and (c) that they should be related to NO_x emissions in the exponential form indicated in Eq. (2-1). This is considered a significantly different and more realistic approach to the analysis of data involving a large number of independent variables. The usual approach involves lumping all of the anticipated independent variables into an extended polynomial correlation equation involving each of the independent variables directly. The approach in this study, however, does introduce the problem that the terms in the resulting correlation equation are not entirely independent of each other. For example, the combustion air temperature enters into all but the bound-nitrogen term in the correlation equation. This problem must be kept firmly in mind when interpreting the results of the correlations. The objective of this study, as stated in Section 1, is to learn as much as possible from the data about the fundamental combustion processes which influence NO_x emissions and not necessarily to establish influence coefficients for each of the independent variables.

2.1.3.1 Data Samples

Table 2-1 provides a description of the furnace geometry input variables and a number of furnace-related derived variables used in the correlation equation. The furnace designation (PQ) is not an input variable. The flow area of the burner (AB) is calculated from the burner diameter (HWB) and, therefore, is not an independent variable. The mixing zone dimensions are all derived from the furnace geometry. The cooling factor essentially accounts for variations in furnace cooling surface-to-volume and flow rate ratios. It is derived from furnace geometry and operating variables. The FGR flow rate constants are empirically derived as a means of converting measured flue gas fan amperage to flue gas flow rates. As such, they represent one independent input variable concerning operating conditions. (These derivations are discussed in Appendix A.) The air flow admittances are derived empirically from air flow rate and windbox-furnace pressure drop data (discussed extensively in Section 3). These three admittances represent three additional independent input variables which might be considered related to operating conditions. Thus, Table 2-1 includes nine independent input variables related to furnace geometry and four independent variables related to operating conditions. Values of these variables are listed in Table 2-2.

In addition, each of the burners in the total burner array can be operated independently in one of three configurations: (a) (F+A), (b) (Air), or (c) shut off completely (fuel valves shut off and air registers closed). NO_x ports can be open or closed by means of a damper. Variations in the operating configurations of the individual burners and the NO_x ports are a large part of techniques to reduce NO_x; the configuration used represents a number of additional independent input variables equal to the number of burners plus the NO_x ports. This number of additional input variables ranges from 12 in the smallest boiler to 25 in the largest.

Table 2-1. DESCRIPTION OF BOILER-SPECIFIC INPUT VARIABLES

PQ = Boiler designation code

- P = Plant name
  - H = Haynes
  - S = Scattergood
  - L = Harbor (Long Beach)
- Q = Specific boiler number within the plant

NT = Total number of burners

NFW = Number of firing walls

IWD = Number of burners on a given vertical level

NNP = Number of NO_x ports

HWF = Horizontal width of the furnace, between nonfiring walls

HDF = Horizontal depth of the furnace, between firing walls (opposed) or between firing wall and back wall (single wall)

HBB = Vertical height between burner levels

HBNP = Vertical height between the top level of burners and the NO_x ports

AB = Cross-sectional flow area of the burners

HWB = Horizontal width of the burners (diameter of the burners)

ZLP[a] = Length of the primary mixing zones

ZLS[a] = Length of the secondary mixing zones

ZLAO[a] = Length of the adjacent and opposite mixing zones

ZLNP[a] = Length of the NO_x port mixing zones

Table 2-1. DESCRIPTION OF BOILER-SPECIFIC INPUT VARIABLES (Continued)

ZLF[a] = Length of the final mixing zone

FCF = Furnace cooling factor (Appendix A)

FRA, FRB = Constants in the FGR flow calculation from flue gas fan amperage

ADMNP[b] = Admittance of one NO_x port

ADMA[b] = Admittance of an (AIR) burner

ADMFG[b] = Admittance of an (F+A) burner with gas fuel

ADMFO[b] = Admittance of an (F+A) burner with oil fuel

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[a] All lengths in the flow direction.

[b] All admittances are for air flow through the burners

Table 2-2. VALUES OF BOILER-SPECIFIC INPUT VARIABLES

Variable code	Unit	Boiler type				
		H1/2	H3/4	H5/6	S1/2	L3
		Furnace-burner geometry				
NT	-	12	12	24	16	12
NFW	-	1	2	2	1	1
IWD	-	4	4	4	4	6
NNP	-	0	4	2	0	0
HWF	ft	49.06	36.0	33.04	39.41	36.58
HDF	ft	24.0	28.0	30.0	24.25	21.0
HBB	ft	8.0	8.0	3.67	6.5	5.63
HBNP	-	-	7.0	9.43	-	-
AB	ft^2	7.069	7.069	5.241	4.273	3.681
HWB	ft	3.0	3.0	2.583	2.333	2.165
		Mixing zone				
ZLP	ft	6.0	6.0	5.17	4.667	4.33
ZLS	ft	6.0	3.0	3.28	6.545	5.56
ZLAO	ft	12.0	6.0	6.56	13.05	11.11
ZLNP	ft	-	10.0	10.0	-	-
ZLF	ft	40.0	40.0	52.0	34.0	28.0
		Cooling factor				
FCF	-	1.742	1.343	1.0	2.177	2.147
		FGR flow				
FRA	lb/sec-amp	3.947	1.579	1.825	0.538	0
FRB	amp	9.2	22.7	15.27	35.5	0
		Burner air flow admittance				
ADMNP	ft-lb$^{1/2}$/sec	0	2.5	10.0	0	0
ADMA	ft-lb$^{1/2}$/sec	10.0	10.0	5.4	6.0	-
ADMFG	ft-lb$^{1/2}$/sec	4.635	5.056	4.036	3.100	-
ADMFO	ft-lb$^{1/2}$/sec	5.277	7.114	4.692	4.252	-

To convert from	to	Multiply by
ft	m	0.3048
lb	kg	0.4536
ft-lb$^{1/2}$/sec	m-kg$^{1/2}$/sec	0.2053

Only three other variables related to operating conditions are considered primary independent input variables in this study: (a) the fuel flow rate, (b) the total combustion air flow rate, and (c) the combustion air temperature. The fuel flow rates are directly measured by flow-meters. In nearly all cases, the air flow rates were calculated from the A/F ratios, determined from the ratio of O_2 and CO_2 in the flue gas analyses and the measured fuel flow rates. Combustion air temperatures were measured only at the exit to the air preheater and, lacking any other data, were taken as the combustion air temperatures in the windbox.

Thus, the total number of independent variables which can enter into the correlation equation is potentially as high as 41: (a) 9 related to fixed furnace geometry, (b) 4 related to fixed operating conditions in a given furnace, (c) 12 to 25 related to variable burner configurations, and (d) 3 related to variable operating conditions. This strongly influences the size of the data sample necessary for meaningful correlation. No specific attempt was made in this study to evaluate the relative significance of these variables.

In some cases, not all of the data necessary to calculate values of the primary independent operating condition variables were recorded. This was particularly true of the combustion air temperatures. In anticipation of this problem, a number of intermediate empirical correlations were established relating the desired primary variables to other more commonly recorded secondary data. These were used to fill in missing data. In all cases, the measured fuel flow rate and combustion air temperatures, as well as the air flow rate calculation, were used where all necessary data were available. Significant data conversion calculations and the intermediate correlations are discussed in Appendix C. A summary of the data sample is contained in Table 2-3. A listing of values of boiler load, air and fuel flow rates, A/F ratios, FGR flow rates, and combustion air temperatures are

Table 2-3. SUMMARY OF THE TOTAL DATA SAMPLE

Boiler type	Rated load, MW	Firing type	NO_x ports	No. of burners	Boiler code	No. of tests		
							Gas	Oil
H1/2	240	Single wall	No	12	H1		11	12
					H2		20	33
						Total	31	45
H3/4	240	Opposed	Yes	12	H3		39	6
					H4		12	8
						Total	51	14
H5/6	350	Opposed	Yes	24	H5		115	39
					H6		30	22
						Total	145	61
S1/2	180	Single wall	No	16	S1		7	18
					S2		33	23
						Total	40	41
-	82	Single wall	No	12	L3		8	16
						Total	-	-
					Total samples		275	177
					Total gas and oil samples		452	

listed in Appendix D, along with the measured values of NO, O_2, and CO_2, for each boiler and test condition. A brief discussion of the flue gas analysis technique and apparatus is also contained in Appendix D.

2.1.3.2 Preliminary Correlations

The initial correlation equation consisted of 24 terms: 22 describing the thermal NO_x generation in the various types of mixing zones, 1 for bound-nitrogen conversion, and 1 constant. As discussed in Appendix A, this was reduced to eight terms for thermal NO_x, plus the bound-nitrogen term and the constant. The regression analysis program analyzed the significance of each of the terms used in the correlation equation. Early correlations indicated that the "final-final" mixing zone, downstream of the NO_x port mixing zone, plus some of the individual bulk gas mixing zones, were of little significance to the correlations. The "final-final" zone term therefore was eliminated, and all six of the bulk gas zones were combined into one term. Other combinations of terms resulted from consideration of the number of independent variables in the correlation equation and the size of the data samples to be correlated.

The remaining 18 terms in the correlation equation represented 18 unknown linear coefficients to be determined by correlation of the data and as many as 41 independent variables. Theoretically, the 18 unknown coefficients could be determined with only 18 sets of data, in which all of the terms in the correlation equation varied. In fact, correlation of such a data sample could be exact, with a correlation coefficient of 1.0. If there is significant data scatter or the variations of some of the terms are small, an extremely strange correlation could result, indicating erroneous influences of the terms. It might be possible, however, for different combinations of the 41 possible independent variables represented in the 18-term equation to yield the same values for the 18 terms but different values of NO_x.

The 18 coefficients determined by correlation, then, would also be different. Thus, a data sample significantly larger than the number of terms in the correlation equation, perhaps larger than 41, was necessary to assure that a best estimate of the coefficient of each term was derived. For evaluation of the best combination of terms in the correlating equation for the data subsamples of interest, a number of correlations were made with different numbers and combinations of terms. A decision on the appropriate terms for the desired data samples was based partly on the correlation coefficients resulting from these correlations.

The correlation coefficient R is defined as

$$R = \sqrt{1 - \frac{VRES}{VNO}} \qquad (2-2)$$

where VRES is the variance of the differences between the measured values of NO and the values of NO calculated from the correlation equation and VNO is the variance of the differences between the measured values of NO and the average value of NO of the data sample.

In 108 test conditions including all boilers and both gas and oil fuels, NO emissions were simultaneously sampled and independently analyzed by two of three different organizations. The standard deviation of the differences between these analyses was 29.9 ppm, and standard deviation of the NO sample itself was 117.6 ppm. Thus, even if the values of NO calculated from the correlation equation were exactly correct, the correlation coefficient, Eq. (2-2), could not be higher than 0.967. Obviously, similar degrees of random scatter in the measured data are input to the correlation equation. Because of the complexity of the equation, however, it is difficult to estimate the (nonlinear) effect of such scatter on the ultimate correlation coefficient.

On the basis of the effect of NO scatter alone, it was estimated that data scatter in all of the measured data could easily limit the correlation coefficient, for a realistic correlation, to less than about 0.92.

If the data sample or the range of data variations becomes too small for the number of terms in the correlating equation, correlation coefficients greater than 0.92 could be obtained. This would indicate that the correlation was being dictated by random scatter in the measured data rather than by true physical relations between the variables. Therefore, any data correlations yielding correlation coefficients greater than about 0.9 were viewed with suspicion and avoided. On the lower end, it would be desirable to have correlation coefficients for all data samples near 0.9, to explain as much of the data variation as possible. Thus, the appropriate data samples and terms in the correlating equation were selected, at least partly, to achieve correlation coefficients as high as possible but not greater than 0.9. In some of the correlations obtained during the trial period, correlation coefficients as high as 0.921 were obtained. In this particular case, using 10 terms in the correlation equation to correlate 45 test conditions on 1 boiler type, the coefficients of some of the terms became large positive and negative values. This made the values of NO calculated from the equation extremely sensitive to small changes in the input parameters affecting those terms. Such a correlation equation would be useless in attempting to interpolate or extrapolate the effects on NO_x of those input variables. These considerations also entered into the selection of the data sample sizes to be correlated and the terms to be used in the correlation equation.

The final groupings into the 10 terms used in all correlations discussed are listed and described in Table 2-4. Final correlations involved more than 61 test conditions.

Table 2-4. DESCRIPTION OF TERMS IN CORRELATING EQUATION

Term no.	Zone code	Type of term
1	X1P16	Primary zones at all levels associated with (F+A)
2	X2R16, X2S14, and X2S05	Recirculation zones at all levels and secondary zones at levels 1-5 associated with burner configurations involving (F+A) vertically above (F+A) (or above a zero flow burner); same A/F ratio as 1
3	X4R16, X4S14, and X4S05	Same as term 2 except associated with burner configurations involving (F+A) vertically above (Air)
4	X5R16, X5S14, and X5S05	Same as term 2 except associated with burner configurations involving (Air) vertically above (F+A)
5	X3O01 and X3O02	Horizontally adjacent or opposite zones at levels 1 and 2 associated with burner configurations involving (F+A) adjacent or opposite (F+A) (or adjacent or opposite a zero flow burner); same A/F ratio as 1
6	X6O01 and X6O02	Same as 5 except associated with burner configurations involving (F+A) adjacent or opposite (Air)
7	DNF 1 through DNF 6	All bulk gas zones
8	DNST	NO_x port mixing zone
9	--	Bound nitrogen term
10	--	Constant

2.2 RESULTS

The general objectives of this study were to explain the effects of certain hardware and operating condition variations on NO_x emissions in fundamental combustion terms and to use this increased understanding to suggest practical hardware and operating conditions to achieve minimum NO_x emissions. As with all data correlations, small interpolations within the conditions tested are reasonably reliable but interpolations over large data gaps and large extrapolations outside of the data sample must be treated with care. Such correlations, however, make the interpretation of the effects of hardware and operating conditions on NO_x emissions easier and more reliable. The extrapolations to new untested configurations to minimize NO_x are more difficult and must depend partly on the understanding developed within the range of conditions tested and backed up by available data. This understanding can be achieved by (a) examining the correlation equations themselves, (b) conducting parametric studies with the correlation equations by varying individual input parameters over the range tested, and (c) using the understanding developed to dictate further parametric studies over variable ranges not tested. Each of these processes are discussed in the following paragraphs.

One of the most important areas of understanding to be gained from analysis of this large quantity of data from full-scale multiple-burner boilers is that involving the smaller-scale mixing of the air and fuel from the multiple-burners within the boiler. It would be desirable to track the actual mean molecular A/F (gas or vapor) ratio of each of the burner flows through the various gross mixing zones at the burner level and after mixing with the bulk gases and NO_x port flow.

In gas firings, air and fuel are being mixed in weight proportions larger than 9:1, beginning with gross mixing within the burner. In oil firings, air and fuel vapor mixing proportions start at infinity at the burner and decrease to proportions as low as 9:1 in the furnace as the liquid fuel slowly vaporizes. It seems reasonable to visualize the small-scale mixing process as the addition of fuel to the air. Figure 2-4 is a schematic showing how the mean molecular-scale A/F ratio of the combustion air might change with time as the fuel is mixed in. Since oil fuels must first vaporize before air-fuel vapor mixing can occur, the A/F ratio of the air must change more slowly with oil fuels than with gas fuels. The case shown is one where the burner is being operated off-stoichiometric. Eventually, the mean molecular-scale A/F ratio reaches the same low level for both the gas and oil fuels. Also shown in Figure 2-4 is a band of A/F ratios near stoichiometric where the rate of NO_x generation is high. This band is shown decreasing in width, with time, to simulate the reduction in gas temperature resulting from heat rejection to the water walls.

The schematic shown in this figure is convenient for visualizing several important aspects of the NO_x control problem:

a. According to the A/F ratio, temperature, time-history approach to minimum NO_x emissions, it is necessary to control the mean molecular-scale A/F ratio so that it skirts the edges of the high NO_x generation zone or spends as little time in it as possible.

b. Those regions in the furnace where this mean A/F ratio crosses the high NO_x rate zone should appear in the correlation equation as regions of proportionally large contributions of NO to the total.

c. The region where this mean A/F ratio first crosses the high NO_x zone, in the initial mixing with and within a given burner flow, compared with the region where this same burner flow enters the bulk gases (enters a region of significant mixing with the already mixed flow from burners below) is critical to the arrangement of operating (F+A) burners and (Air) burners in the multiple burner array.

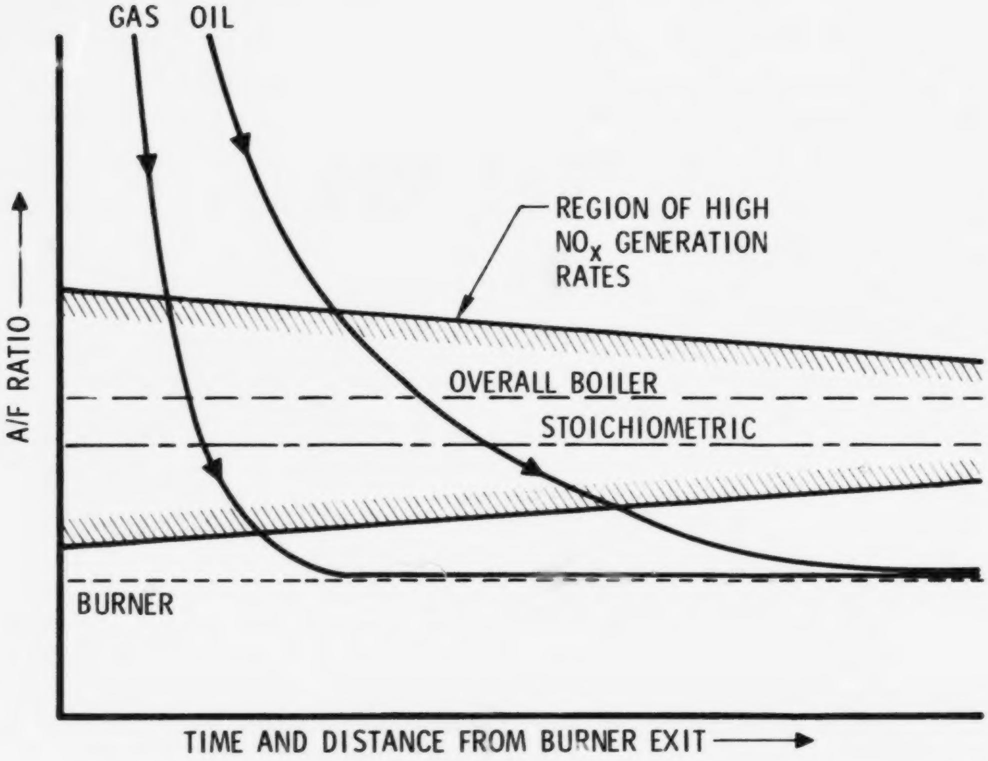

GAS
OIL
REGION OF HIGH
NO_x GENERATION
RATES
OVERALL BOILER
STOICHIOMETRIC
BURNER
A/F RATIO
TIME AND DISTANCE FROM BURNER EXIT

Figure 2-4. Schematic of possible variations of the average molecular scale A/F ratio of the combustion air as gas or oil-vapor mixes with it

In the initial development of the correlation equation, the assumption was made, although it was known to be incorrect, that all air-fuel mixing was complete, on a molecular scale, in the flow leaving the burners. This assumption results in calculated values of the NO contributions from the early mixing zones, which are too high. If the correlations of the data are good, however, small coefficients will be assigned to those terms representing these early mixing zones such that the assumption error is corrected. The resulting indications of the effects of each of the zones on the NO variations should still indicate where in the furnace the mean molecular-scale mixing is in, or is slowly passing through, the high NO_x generation zone of Figure 2-4.

2.2.1 Observations Directly from the Correlations

Table 2-5 shows the coefficients obtained from the correlation of various data samples, using the 10-term correlation equation described in Table 2-4. The correlations are grouped separately for natural gas and low-sulfur oil fuels. The correlation coefficients shown in the table represent correlations of data from a single boiler (H5) or a boiler type consisting of two identical boilers (H5/6), opposed-fired boilers using NO_x ports (H3/4 + H5/6), single-wall-fired boilers without NO_x ports (H1/2 + S1/2) and all data for a single fuel. The number of test conditions used in each of the correlations and the resulting correlation coefficients are also shown in Table 2-5.

The correlation coefficients of the gas-fired data shown in Table 2-5 are all in the desired range, indicating good but not misleading correlations. The correlation of the single-wall-fired boilers without NO_x ports (H1/2 + S1/2), involving only 71 test conditions, shows a correlation coefficient slightly above 0.9. The abnormally large coefficients for terms 7 and 8 show the tendency toward a high correlation coefficient but, perhaps, a misleading correlation when the amount of data correlated becomes relatively small. The gas

Table 2-5. COEFFICIENTS OF THE TERMS IN THE CORRELATION EQUATIONS FOR VARIOUS DATA SAMPLES

Term no.	Natural gas fuel data samples				
	H5	H5/6	H3/4 - 5/6	H1/2 - S1/2	All gas
1	-12.50	-12.08	-0.9526	-0.6629	-0.4271
2	+9.922	+9.576	+0.6911	+0.6744	+0.3927
3	-0.2062	-0.3184	-0.0646	+0.2729	-0.0182
4	-6.126	+154.0	-192.4	-418.8	-167.1
5	-10.11	-9.720	-0.1465	-2.276	-0.2393
6	+0.5255	+0.1464	+0.7776	+6.744	+0.8473
7	+4.383	+4.971	+3.043	-154.1	+3.473
8	+17.82	+8.725	+15.20	+1150	+20.07
Constant	+201.1	+213.4	+220.6	+101.8	+184.7
No. of tests	115	145	196	71	267[a]
Correlation coefficient	0.841	0.859	0.844	0.902	0.837

[a] 8 tests on L3 not used in correlation

Table 2-5. COEFFICIENTS OF THE TERMS IN THE CORRELATION EQUATIONS FOR VARIOUS DATA SAMPLES (Continued)

Term no.	Low-sulfur oil fuel data samples			
	H5/6	H3/4 - 5/6	H1/2 - S1/2	All oil
1	+0.6693	+0.1876	-0.00623	-0.0221
2	-0.5180	-0.1315	+0.01304	+0.0261
3	-0.4389	-0.3846	+0.1234	-0.0280
4	+1401	+1123	-433.1	-139.5
5	+0.5043	+0.0643	+0.3417	-0.0233
6	+0.7910	+0.6324	+2.388	+1.480
7	+0.5915	+0.7151	-19.45	+0.4563
8	+2.589	+2.306	+148.0	+3.659
9	-5.028	-1.551	+1.260	+2.573
Constant	+1012	+457.2	-13.72	-205.9
No. of tests	61	75	86	161[a]
Correlation coefficients	0.860	0.849	0.680	0.734

[a] 16 tests on L3 not used in correlation.

correlations also show that the correlation coefficients are relatively constant regardless of the variety of types and sizes of boilers introduced into a single correlated data sample. The correlation of all of the gas-fired data yields a correlation coefficient nearly identical to that for the single boiler (H5) sample alone.

The correlations of the oil-fired data show good correlation coefficients for all of the data groupings except those involving the single-wall-fired boilers (H1/2 + S1/2). The poor correlation is related to the S1/2 data. The data sample on S1/2, however, is too small (41 tests) to properly evaluate that correlation alone. Correlation coefficients for the S1/2 data only are 0.960 and 0.503 for gas and oil, respectively. An error in the S1/2 oil-fired input data is suspected. At this writing, that error has not been found.

The coefficients listed in Table 2-5 are not sufficiently revealing with respect to the NO_x generation processes without the calculated values of the corresponding parameters. Average values of these parameters, therefore, were calculated for each data sample and are shown in Table 2-6. The products of the coefficients and the parameters for each term yielded values in units of NO, ppm, which can be thought of as influence coefficients of the zones and burner combinations represented by each term of the total NO_x emissions. The values of these terms are listed in Table 2-7.

The gas correlations involve constants with values over the positive range from 101 to 221 ppm. In the oil correlations, the term representing the bound nitrogen (term 9) for any one correlation is also essentially constant. The effective constants for the oil correlations, shown in Table 2-7 as "9 + CONSTANT," also have values over the positive range, between 187 and 239 ppm. The variations in total NO_x emissions, therefore, are controlled by terms 1 through 8.

From the standpoint of distance within the furnace from the burner exits, term 1 is closest, representing the primary zones starting at the burner exits. Terms 2 through 4 represent the recirculation and secondary zones. Terms 5 and 6 represent the more distant adjacent and opposite mixing zones, while term 7 represents the bulk gas zones and term 8 the NO_x port zone. Considering the correlations of the largest, most complex boiler type (H5/6) and the correlations of all gas and oil data, an initial estimate of the influence of distance from the firing walls on the variations in NO_x can be generated. Summing those terms in Table 2-7 describing the same mixing zones yields the following:

Zone	Value of terms			
	H5/6		All data	
	Gas	Oil	Gas	Oil
Primary	-3376	+ 975	-120	-26
Recirculation and secondary	+4251	-1204	+146	+38
Adjacent and opposite	- 849	+ 225	- 14	- 3
Bulk gases	+ 75	+ 49	+ 36	+15
NO_x ports	+ 15	+ 6	+ 9	+ 3

Several preliminary observations can be made from these data: (a) The NO_x variations with gas fuels are strongly dominated by variations in the early mixing zones, while those with oil fuels are more distributed; (b) the variations in NO_x with both fuels are more distributed and are proportionately about the same for gas and oil when the smaller single-wall-fired boilers are added into the sample; and (c) the effects of mixing zones at a given furnace level (exclusive of the bulk gas and NO_x port zones) are opposite between gas and oil fuels in the large boiler.

One of the most important observations obtained from this data analysis concerns the location within the furnace where the mean small-scale A/F ratio is in, or is passing through, the region

Table 2-6. AVERAGE INPUT VALUES FOR THE PARAMETERS IN EACH VARIABLE TERM IN THE CORRELATION EQUATIONS FOR THE VARIOUS DATA SAMPLES

Term no.	Natural gas fuel data samples				
	H5	H5/6	H3/4 - 5/6	H1/2 - S1/2	All gas
1	269.7	279.5	258.7	342.3	281.0
2	427.1	445.8	408.7	408.3	408.6
3	81.60	87.42	70.72	65.32	69.28
4	0.0551	0.0622	0.0817	0.0707	0.0788
5	84.20	90.50	89.11	7.650	67.45
6	2.904	2.304	3.148	1.568	2.728
7	16.95	18.14	13.88	0.1319	10.22
8	0.8117	0.7646	0.5716	0.0272	0.4268

Table 2-6. AVERAGE INPUT VALUES FOR THE PARAMETERS IN EACH VARIABLE TERM IN THE CORRELATION EQUATIONS FOR THE VARIOUS DATA SAMPLES (Continued)

Term no.	Low-sulfur oil fuel data samples				
	H5	H5/6	H3/4 - 5/6	H1/2 - S1/2	All gas
1	(not corre-lated)	1456	1485	918.9	1183
2		2298	2392	1150	1729
3		125.3	101.9	92.39	96.81
4		0.0296	0.0240	0.0414	0.0333
5		445.3	546.8	30.09	270.8
6		0.8339	0.6783	3.888	2.393
7		82.65	69.84	0.1429	32.61
8		2.303	1.931	0.0185	0.9095
9		159.5	158.4	159.0	158.7

Table 2-7. AVERAGE VALUES OF THE TERMS IN THE CORRELATION EQUATIONS FOR THE VARIOUS DATA SAMPLES

Term no.	Natural gas fuel data samples[a]				
	H5	H5/6	H3/4 - 5/6	H1/2 - S1/2	All gas
1	-3371	-3376	-246	-227	-120
2	+4238	+4269	+283	+275	+161
3	-17	-28	-5	+18	-1
4	-0	+10	-16	-30	-13
5	-851	-880	-13	-17	-16
6	+2	+0	+2	+11	+2
7	+74	+90	+42	-20	+36
8	+15	+7	+9	+31	+9
Constant	+201	+213	+221	+102	+185
Totals	+296	+305	+277	+143	+243

[a] Units of each term in ppm

Table 2-7. AVERAGE VALUES OF THE TERMS IN THE CORRELATION EQUATIONS FOR THE VARIOUS DATA SAMPLES (Continued)

Term no.	Low-sulfur oil fuel data samples[a]			
	H5/6	H3/4 - 5/6	H1/2 - S1/2	All oil
1	+975	+279	-6	-26
2	-1190	-315	+15	+45
3	-55	-39	+11	-3
4	+41	+27	-18	-5
5	+225	+35	+10	-6
6	+1	+0	+9	+4
7	+49	+50	-3	+15
8	+6	+5	+3	+3
9	-802	-246	+200	+408
Constant	+1012	+457	-14	-206
Totals	+262	+253	+207	+229
No. 9 and constant	+210	+211	+186	+202

[a] Units of each term in ppm.

of high NO_x generation rates. The data show that the NO_x variations possible in the primary, recirculation, and secondary zones are larger than those in the bulk gas zones by about a factor of 50 for gas fuels but by only a factor of about 20 for oil fuels in the large boiler. Even the total data samples for each fuel show that these zones are in the ratio of about 3.5 for gas to 2.1 for oil. The adjacent and opposite mixing zones in the large boiler are also about three times as significant with gas fuels as with oil fuels. In the total data sample, however, the adjacent and opposite zones are small compared with the bulk gas zones for both fuels. A general preliminary observation from this data might be that the small-scale mixed A/F ratio for gas fuels passes rather quickly through the region of high NO_x generation rate in the early mixing zones (but not completely in the primary zone), while that for oil passes through more slowly and over a larger distance into the furnace. These observations are not surprising except, perhaps, that the gas mixing is apparently not complete in the earliest (primary) mixing zones.

The more distributed effects of the various zones on the NO_x with the smaller boilers added into the sample are also not very surprising when the definitions of these zones are considered. The larger boiler has six vertical levels of burners with no divider wall, while all other boilers have only 3 to 4 vertical levels and most have a divider wall of some type. Thus, the early mixing between burners, both vertically and horizontally, tend to disappear, and the boiler begins to approach the behavior of a single-burner boiler. Hence, the data from the smaller boilers provide less information on the effects of multiple-burner arrays on NO_x, and the multiple-burner configuration effects tend to become obscured. The correlations tend to be about the same for gas and oil fuels when the smaller boilers are included in the data sample. Single-burner laboratory-type information is much more applicable in these cases.

The data for the large boiler type show that the algebraic signs of the first three mixing zone types are exactly opposite for the cases of gas and oil fuels. This is a significant observation, which is discussed throughout this report. Table 2-7 shows that recirculation and secondary zone effects (terms 2 through 4) on NO_x are dominated in the large boiler correlations by term 2. This term represents those burner configurations where an (F+A) burner is directly below any given (F+A) burner. Term 1 represents those configurations where that same given burner is (F+A). Obviously, these two terms are not independent of each other with respect to burner configurations. A configuration where a given burner is in the bottom row is considered, in this model, to be the same as one which has an (F+A) burner below it, because the same A/F ratio results in the recirculation and secondary mixing zones. An (F+A) burner in the top two rows, in this model, yields a smaller value for term 2 because the model assumes that the bulk gases have spread sufficiently to reduce, and eliminate in the top row, the secondary mixing zones. In the top row, flows from the primary and recirculation zones issue directly into and mix with the bulk gases. Starting with a burner array where all burners are (F+A), term 1 will always be reduced by the effect of one (F+A) burner if the fuel to one burner is shut off. Term 2, however, will be reduced differently, depending on where the resulting (Air) burner is located vertically in the burner array: (a) If the (Air) burner is in levels 1 to 4, the number of configurations involving two vertically adjacent (F+A) burners will be reduced by two (both vertical combinations involving the (Air) burner); (b) if the (Air) burner is in the top level, the number of vertically adjacent (F+A) burner configurations will be reduced by only one since there is no (F+A) burner above it; and (c) if the (Air) burner is in either of the top two levels, the reduction in the value of term 2 will be less because the secondary mixing zones are reduced or absent at these levels.

Similarly, the effects of the adjacent and opposite mixing zones in the large boiler correlations are dominated by term 5, representing adjacent and opposite mixing between flows from two (F+A) burners on the same vertical level. Because of the bulk gas spreading, however, this kind of mixing was assumed to occur only in the bottom level and partially in the second lowest level.

The foregoing observations may seem to be strongly dependent on the specifics of the model used here. These are the specifics, however, which were input to the correlation equation. The subsequent correlations roughly compensate for the inaccuracy of the specific inputs by determining the appropriate coefficients to best fit the real data.

The large boiler correlations (Table 2-7) show that to reduce NO_x emissions with gas fuels it is desirable to keep the value of terms 1 and 5 as large as possible while reducing the value of term 2. The case of oil, however, is exactly the opposite, and the conclusions, therefore, are opposite. For gas fuels, these conclusions indicate that the total number of (F+A) burners should be kept as large as possible (to maximize term 1) and no (Air) burners should be located in either the bottom two levels or the top two levels of the burner array (to maximize term 5 and minimize term 2). This implies just a few (Air) burners located in the vertical midlevels of the array. For oil fuels, the data indicate that a larger number of (Air) burners should be used (to minimize term 1) and these (Air) burners should be located either in the top level (to maximize term 2) or in the bottom row (to minimize term 5). For minimum NO_x, the better of these two locations is dependent on the relative variations in terms 2 and 5 and, perhaps, on the additional effects of (Air) burners in these levels on bulk gas emissions (term 7). In smaller boilers, with less freedom in vertical location of (Air) burners, both gas and oil fuel data tend to look like the gas case, except that the bulk gas and NO_x port zones may be more important. The effect of even a single (Air) burner located at various vertical levels in a furnace is shown schematically in Figure 2-5. (Air) burners located low in the furnace keep the bulk gas A/F ratio above that of the overall furnace throughout the burner region. A single (Air) burner located in the top row may cause the bulk gas A/F ratio to remain close to stoichiometric throughout most of the burner region. Larger numbers of (Air) burners at these locations, of course, would drive the A/F ratios shown in Figure 2-5 to much lower and higher values.

These general observations on the correlation equations tend to verify the slower mixing of the air and fuel vapor in the case of oil fuels, as postulated in Figure 2-4. There is some indication, however, that the air-gas fuel mixing may be slower than expected and may not be complete before the burner flows at the highest levels are forced to mix with the bulk gas flow coming from lower levels. A first indication of appropriate (F+A) and (Air) burner configurations for minimum NO_x can also be obtained. These best configurations may be exactly opposite for gas and for oil fuels in large multiple-burner boilers but may be quite similar in smaller boilers with a limited number of vertical levels. Further understanding of the correlation equations can also be obtained by parametric exercise of the correlation equations.

2.2.2 Parametric Studies of the Correlations

In this section, discussion concerns some of the parametric computer runs intended to further explain the correlation equations. Subsequent sections discuss parametric studies conducted to explain the effects of the combustion modifications tested and those conducted to extrapolate, beyond the existing data, conditions leading to minimum NO_x emissions. The primary question addressed in this section, however, is the meaning of the constants in the correlations.

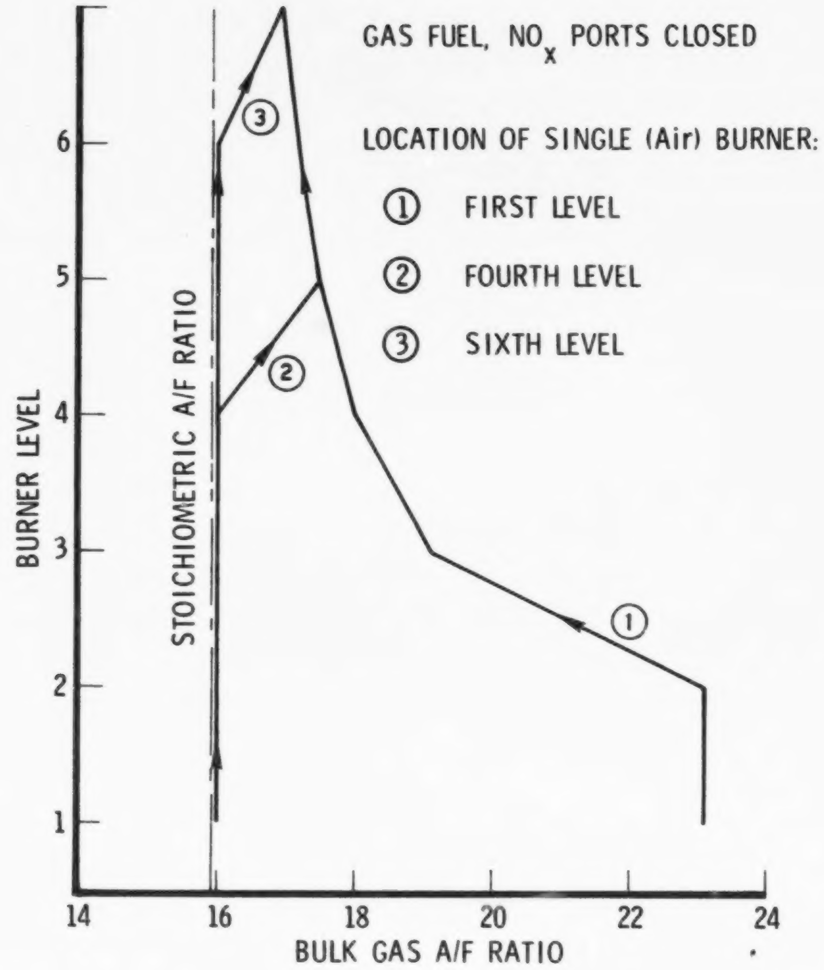


Figure 2-5. Effects of a single (Air) burner on the bulk gas A/F ratio through the H5 boiler

Obviously, the NO contributions from each mixing zone and term in the correlation equation, in reality, are positive. The correlations, however, are positive and negative variations around a constant. If the constant were properly distributed among the various terms, each term would be positive. The difficulty in this case, however, is that those conditions which would yield a zero value of NO when all of the variables go to zero (a zero intercept) are not in the data sample since no zero NO measurement was ever obtained. To force a zero intercept in this case could represent an excessive and perhaps erroneous extrapolation. In these empirical correlations, then, it is unlikely that the intercept would be zero. Care must be taken in parametric exercising of the correlation equations to avoid drawing fundamental conclusions from extrapolations far beyond the existing data.

Only one term in the gas correlations is very nearly constant, i.e., term 8, the NO_x port mixing zone. Since all of the air and fuel flows are involved in this zone, regardless of whether the NO_x ports are open or closed, the A/F ratio is the overall furnace ratio and varies only slightly with overall excess air. The temperature in the zone depends only on the total cooling of the burner flows enroute to this zone and the initial combustion air temperature. Since this zone is always within the A/F ratio region of high NO_x generation (Figure 2-4), it might be expected that the NO_x contribution from this zone is relatively high compared with other zones, unless the cooling rate is high. In the correlations of gas-fired data, therefore, the average value of the NO_x port zone contribution to the total NO_x emissions might be better represented by the sum of the constant and the smaller variable term 8. The same is true for oil fuels if the constant is taken as term 9 plus the true constant.

The possibility that the constant in the gas correlations is associated with the NO_x port zone can be investigated on the basis of operating conditions in a real boiler: (a) If sufficient combustion air flow were diverted to the NO_x ports, the NO_x contributions of all zones except the NO_x port zone should go to zero; (b) if the furnace cooling rate were increased sufficiently, the NO_x contributions from all zones, particularly those further downstream (including the NO_x port zone), should go to zero; and (c) if the combustion air temperature were reduced sufficiently, the NO_x contributions from all zones should go to zero. However, because the combustion air temperature above ambient is small compared with the temperature rise due to reaction, case (c) may not be reached with any realistic reductions in combustion air temperatures. Direct observation of the H5 correlation equation indicates that the limit of NO_x with large NO_x port flows should be slightly larger than the value of the constant. The realistic limits in cases (b) and (c) cannot be determined by direct observation.

The same extreme limits in these three operating condition variables with oil fuels should yield the same results except that, instead of total NO_x values going to zero with high cooling rates and reduced combustion air temperatures, these values should approach that of bound-nitrogen conversion. Again, direct observation of the H5/6 correlation for oil fuels indicates that the limit of NO_x with large NO_x port flows should be slightly larger than the value of term 9 plus the constant (210 ppm). If cases (b) and (c) are realistic, NO_x values should also approach 210 ppm but would then represent the bound-nitrogen conversion. In the investigation of the NO_x variations resulting from these three extremes of operating conditions, the H5 correlation for gas fuel and the H5/6 correlation for oil fuel were used in parametric calculations in which the three variables involved were varied (singly) over wide but realistic ranges.

For case (a), the maximum NO_x port admittance in the data for H5/6 is 4.1 m-kg $^{1/2}$/sec (20 ft-lb $^{1/2}$/sec). It was decided to parametrically increase this admittance to three times the maximum data value, recognizing the degree of extrapolation. For case (b), cooling rates in the smaller boilers, with dividing walls, are as much as 2.2 times higher than that for the H5/6 boilers. In this case, it was decided to also increase the H5/6 cooling rate by a factor of three, again recognizing the degree of extrapolation. For case (c), the data indicate that combustion air temperatures were never reduced more than about 45 degrees K (80 degrees F). With the same factor of three for extrapolation, temperatures no lower than about 440 degrees K 330 degrees F) are obtained. This reduction represents such a small fraction of the temperature of the reactants in any zone that it was unlikely that total NO_x values would be reduced anywhere near zero. Nevertheless, it was decided to make the parametric calculation by reducing the combustion air temperatures to ambient. This represents an extrapolation by more than a factor of six beyond the data.

2.2.2.1 Natural Gas Fuel

Figures 2-6 through 2-8 show the results of the parametric variations of these three operating condition variables for both gas and oil fuels. In the gas fuel case, Figure 2-6 shows that for NO_x port admittance values greater than about 8.4 (40) (about twice the data value for H5), the NO values asymptotically approach a value of 200 ppm, which is the value of the constant for the H5 data correlation. Figure 2-7 shows that increasing the cooling rate for the H5 data to values greater than about 2.9 times the data value decreases the NO to zero and even to negative values. The negative values may indicate the limits of reasonable extrapolation for the cooling rate in this data correlation. Both of these calculations indicate that the constants in the gas fuel correlations are very likely associated with the NO_x port mixing zone. Figure 2-6 also indicates that the single approach of increasing NO_x port flow (two-stage combustion) can be effective initially but cannot reduce NO_x emissions below a still significantly

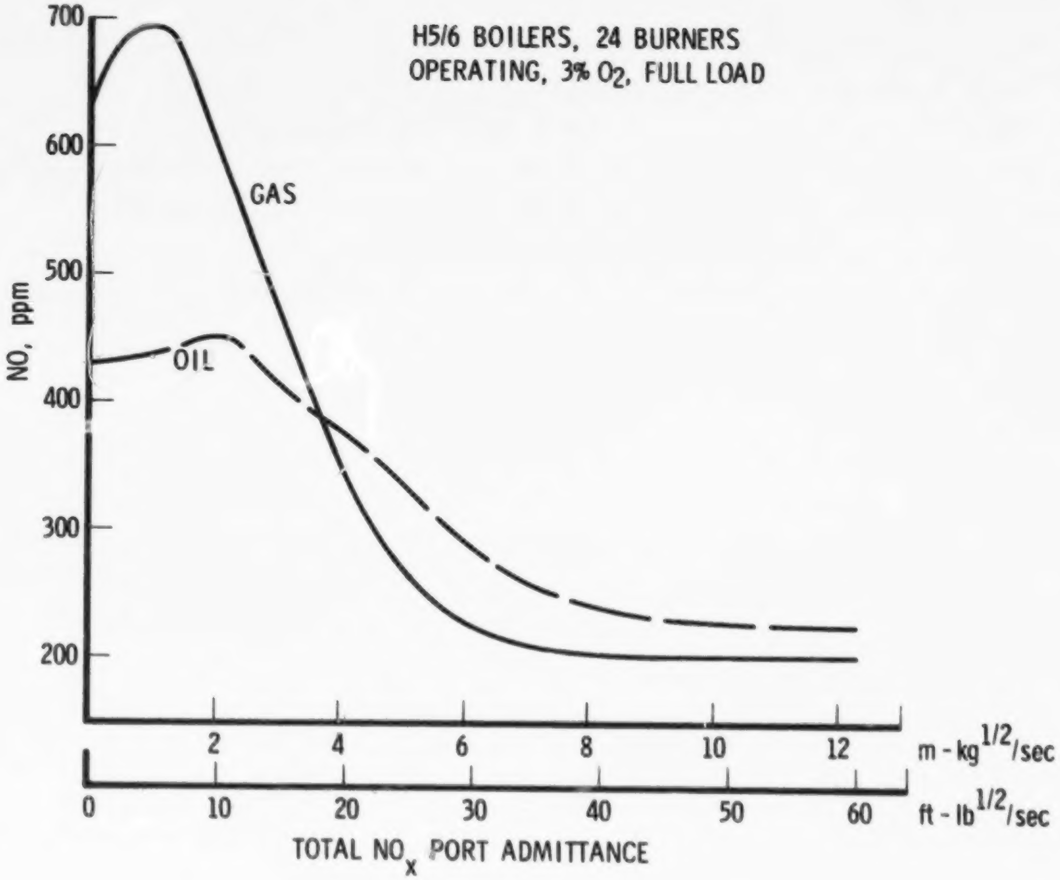


Figure 2-6. Effects of NO_x port admittance

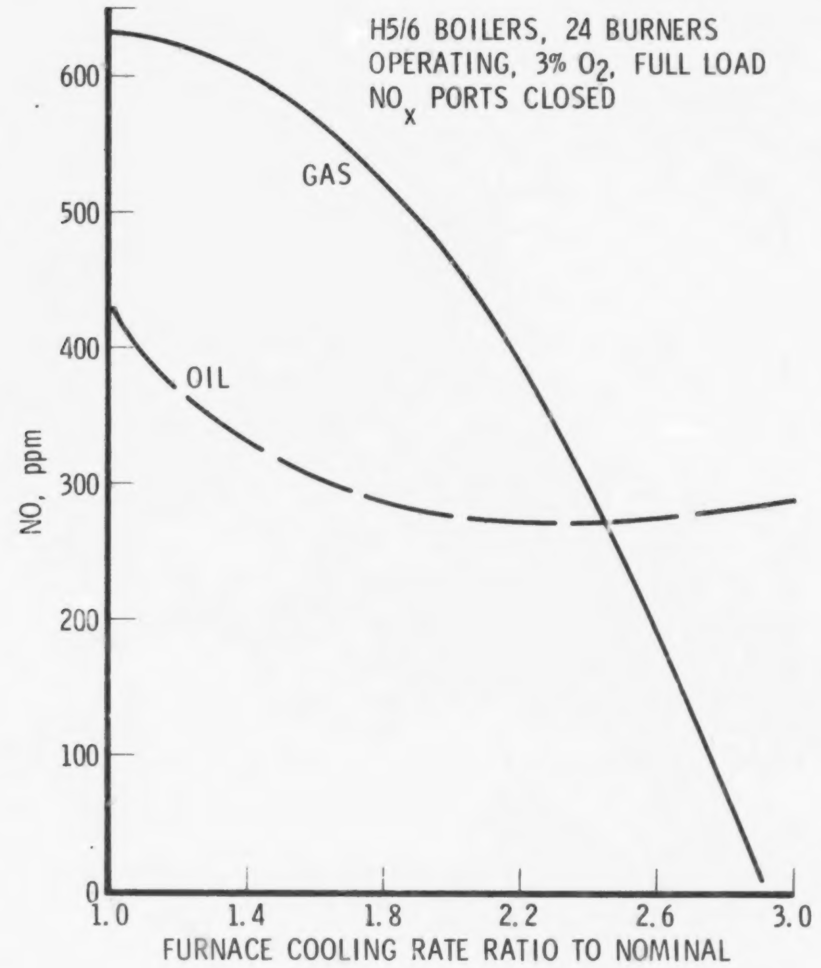


Figure 2-7. Effects of increased cooling rate

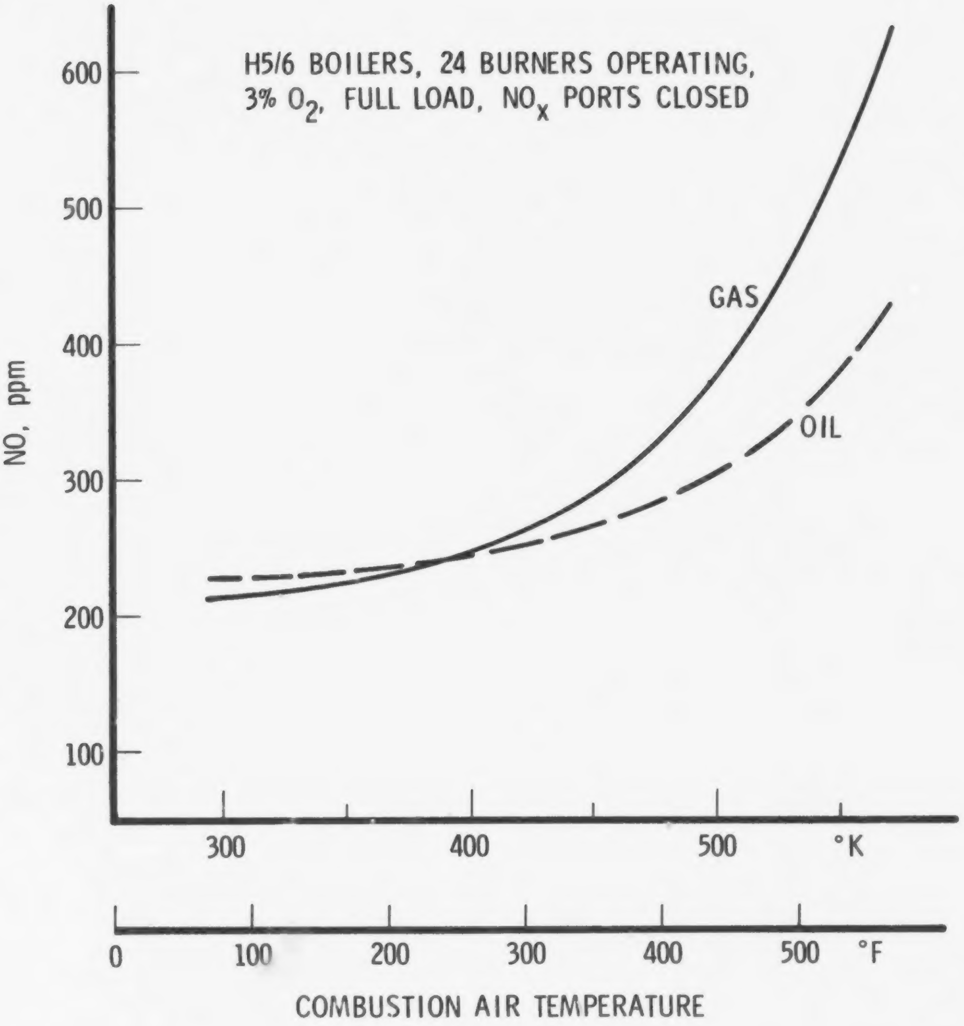


Figure 2-8. Effects of reduced combustion air temperatures

high level. Figure 2-8 appears to indicate that NO values for the gas fuels are asymptotically approaching the value of the constant as combustion air temperatures are lowered. Considering the large range of extrapolation represented by ambient temperatures, however, it is not known whether the calculated NO values are simply not representative with temperatures near ambient or whether a zero NO value might be approached with further reductions. The values of terms 1 through 8, all temperature sensitive terms, have not reached zero with ambient combustion air temperatures.

2.2.2.2 Low-Sulfur Oil Fuel

In the oil fuel calculations, Figure 2-6 shows that for admittance values greater than about 10(50), the NO values approach 225 ppm. This is just 15 ppm greater than the constant (210 ppm). It is entirely reasonable that this 15 ppm represents that part of the NO formed from the fuel-bound nitrogen under these low A/F ratio conditions in the burner region of the furnace. The remaining 210 ppm could reasonably represent that thermal NO formed in the NO_x port zone. Figure 2-7 shows that the calculated values of NO reach a minimum of 270 ppm for cooling rates about 2.3 times the nominal for H5/6. Beyond that cooling rate, the NO values begin to increase again. Since there is no apparent physical reason why this should occur, 2.3 times the nominal cooling rate is considered the limit of extrapolation of this parameter for the H5/6 oil correlation. At this minimum, essentially all sources of thermal NO should be reduced to zero, and the remaining NO should all originate from fuel-bound nitrogen conversion. Figure 2-8 shows that, despite the large extrapolation represented by combustion air temperatures near ambient, the calculated NO values appear to be asymptotically approaching a level which could represent the bound-nitrogen conversion. The low-sulfur fuel oil used contained 0.24 percent bound nitrogen, by weight. If all of this were converted to NO, 353 ppm (dry at 3% O_2) would result. Single burner laboratory tests (Ref. 2-2) indicate that the conversion efficiency for 0.24 weight percent bound nitrogen fired with 3 percent excess O_2 should be about 63 percent. This would yield NO values in this case of 222 ppm. This is very close to the apparent asymptotic value in Figure 2-8 and not too far from the 270 ppm minimum shown in Figure 2-7. For the moment, the agreement appears sufficiently close to indicate that under these low temperature conditions the constant represents the NO from conversion of the fuel-bound nitrogen. Thus, the constant in the fuel oil data correlations must be considered associated with both the NO_x port mixing zone and the conversion of bound nitrogen. Figure 2-6 further indicates that, as in the gas-fuel case, the two-stage combustion approach to NO_x reduction can be initially very effective but cannot reduce NO_x emissions below some still significantly high level.

In general, the parametric studies of the gas correlation equation indicate that the constant should more appropriately be associated with the NO_x port mixing zone, in a form:

$$\text{term } 8' = \text{term } 8 + \text{constant} \qquad (2\text{-}3)$$

For the oil correlation equation, the constant is apparently associated with both the NO_x port mixing zone and the bound nitrogen in a form:

$$\text{term } 8' = \text{term } 8 + \text{term } 9 + \text{constant} \qquad (2\text{-}4)$$

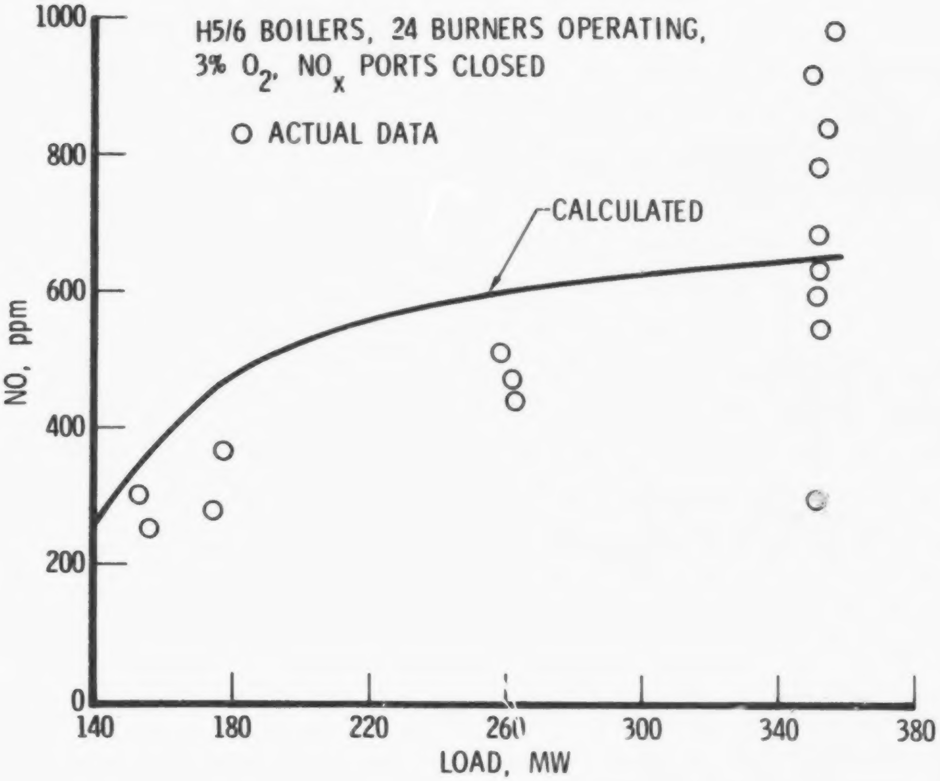
2.2.3 Effects of Some Combustion Modifications

A number of combustion modification techniques to reduce NO_x are represented in the data. These include (a) load and combustion air temperature reduction, (b) NO_x port flow (two-stage combustion), (c) excess air reduction, and (d) various BOOS configurations. Each of these will be discussed separately, supported by such data as is available. Again, the H5 natural gas data sample and the combined H5/6 oil data sample will be used for these discussions.

2.2.3.1 Load and Combustion Air Temperature

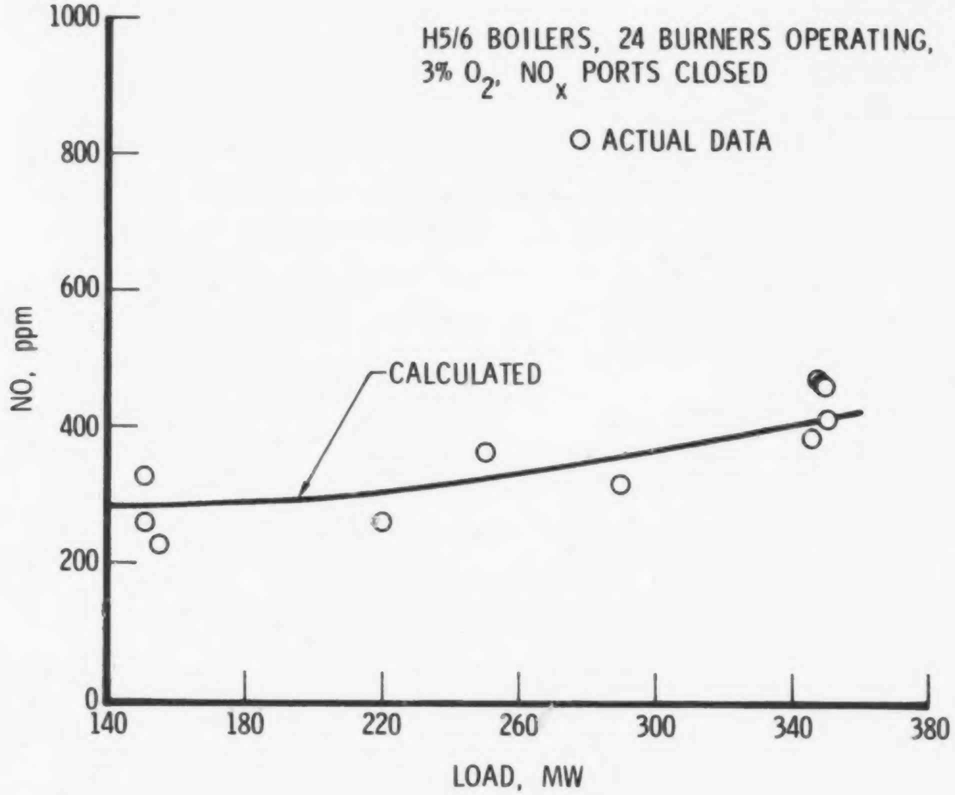
In the parametric evaluation of the effects of load reduction on NO emissions, the only truly independent parameter which was varied was the fuel flow rate. The empirical correlations between fuel flow and load (Appendix C) were used to relate the fuel flow rates to the appropriate plant load. Air flow was calculated from the fuel flow rates to maintain the excess O_2 constant at 3 percent. Combustion air temperatures, however, are known to be dependent on the flue gas flow rates through the boiler and the air preheater. The empirical correlation shown in Appendix C was used to calculate this temperature for each load. In all cases, all burners were operating (F+A), and the NO_x ports were closed. Figures 2-9a and b show the resulting calculation of the variation of NO_x emissions with load for the H5/6-type boilers. Available data are also plotted in these figures. Figure 2-9a shows that the calculated values agree reasonably well with the gas-fired data except at the midload levels. The large scatter in measured NO_x at full load is considered real and will be discussed further. Figure 2-9b shows good agreement with the oil-fired data at all load levels.

Reduced total flow in the calculation of the inputs to the correlating equations results only in longer cooling times for the gases enroute to each of the mixing zones. Since a constant cooling rate with time was assumed, this results in cooler gases in any zone in the furnace Actually, the cooling rate itself may be a complex function of flow rates, particularly, if the mechanism for the overall heat rejection



(a) With natural gas fuel

Figure 2-9. Effects of load variations



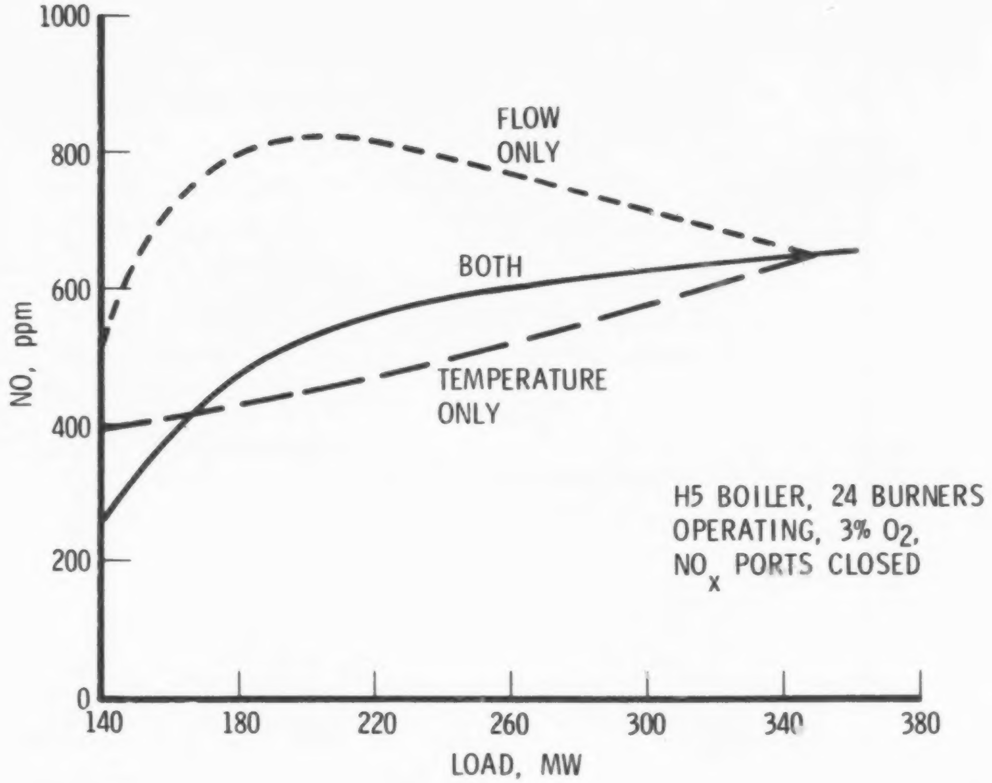
(b) With low-sulfur oil fuel

Figure 2.9. Effects of load variations (Continued)

to the water walls is convective to any large extent. Thus, it is possible that the true average cooling rate could decrease faster with flow rate than the cooling times increase. This case could result in an increase in temperature in some or all of the zones in the radiant section of the boiler and an increase in NO emissions with a decrease in total flow. The temperature of the flue gases at the boiler exit, however, after passing through the entire convective section of the boiler, is clearly reduced. Through the air preheater heat exchanger, the combustion air temperatures, then, are also always reduced.

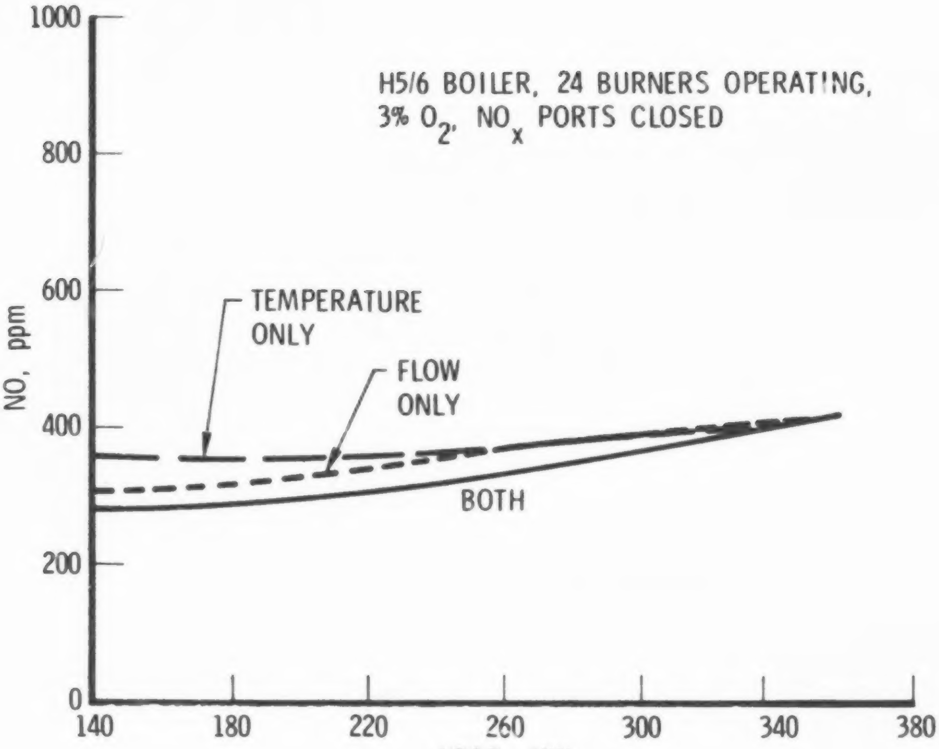
To evaluate these separate effects, the total flow and the combustion air temperatures were varied independently over the ranges corresponding to the load variations of Figures 2-9a and b. The results are shown in Figures 2-10a and b. In the gas fuel case, NO emissions are seen to increase, at first, with decreasing load and then drop sharply. The decrease in combustion air temperature, however, more than compensates for the initial effects of flow reduction such that when both of these parameters vary simultaneously, the NO values always decrease with decreasing load. The fact that the calculated overall NO curve for gas firings does not fit the data well in the middle of the load range (Figure 2-9a) may be due to error in the assumption of a cooling rate independent of total flow. For the oil firings, NO values decrease with either or with both flow and temperature. In this case, the flow reduction appears to have more of an effect than does the temperature.

Figures 2-9 and 2-10 concern the effects of load on a boiler with all burners operating and no NO_x ports. In such a configuration, gas temperatures in the furnace are about as high as occur in any configuration. The effects of those variables associated with load reduction in other configurations, where temperatures may be reduced by air-fuel variations, will be much less. In no case in the test data (applicable to Figures 2-9 and 2-10) did the combustion air



(a) With natural gas fuel

Figure 2-10. Separate effects of total flow and combustion air temperature variations with load



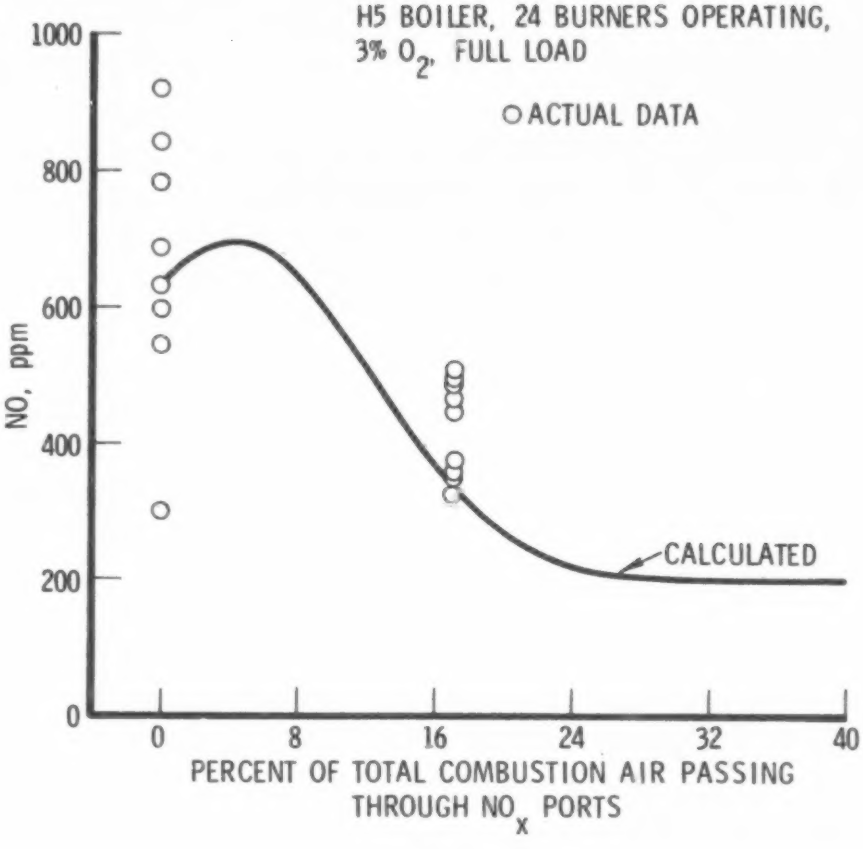
(b) With low-sulfur oil fuel

Figure 2-10. Separate effects of total flow and combustion air temperature variations with load (Continued)

temperature vary independently of load; therefore, these independent trends cannot be verified.

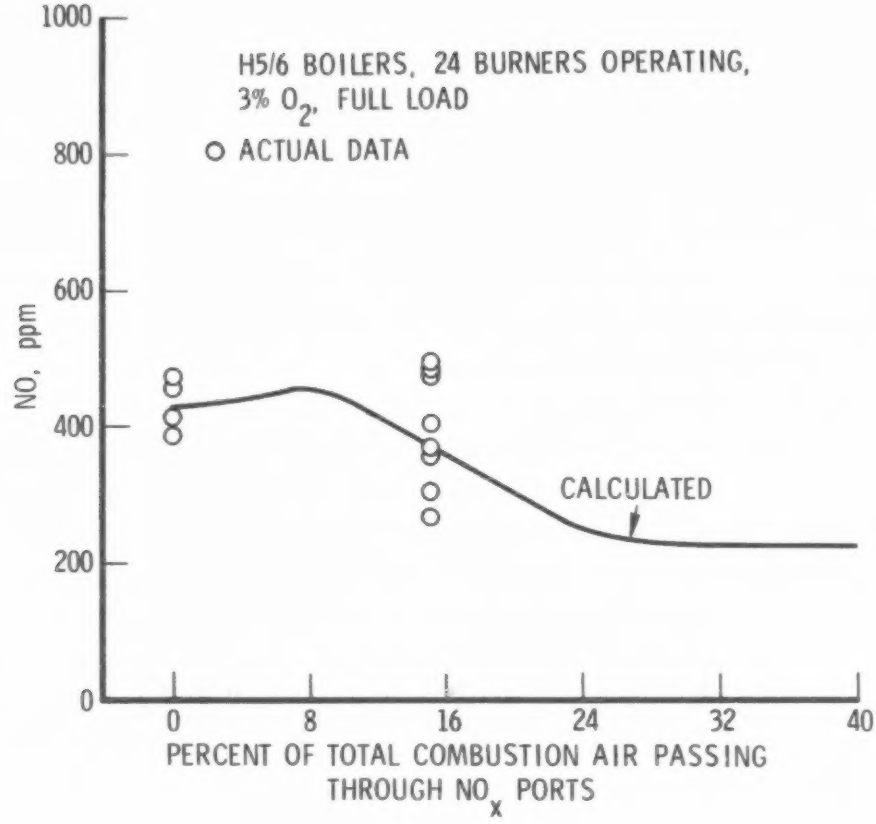
2.2.3.2 NO_x Port Flow

Figure 2-6 shows the independent effects of NO_x port admittance over a very wide range of extrapolation for both gas and oil fuels. To relate this calculation to the fraction of the total combustion air flow diverted through the NO_x ports, values of 19.9 (96.9) and 23.0 (112.6) were used for the total admittance of the 24 operating (F+A) burners (24 times ADMFG and ADMFO, in Table 2-2). These results are shown in Figures 2-11a and b. Since only one NO_x port configuration was used in the H5/6 data sample and only fully open or closed NO_x port data could be used, only two groups of data were available to check the calculation from the correlation equation; NO_x ports either open or closed. The gas fuel calculation (Figure 2-11a) appears somewhat low compared to the NO_x ports open data, but the fit is still reasonable. Again, the wide data scatter with NO_x ports closed is shown. The oil fired calculation (Figure 2-11b) fits the available data very well. In both cases, the slight rise in NO values as the fraction of flow through the NO_x ports begins to increase is due to the burner A/F ratio passing through the high NO_x generation region near stoichiometric. The fraction of flow diverted to the NO_x ports in the current configuration with both gas and oil is such that the burner A/F ratios, with all burners operating, are greater than 11. Further significant reductions in NO could be achieved by increasing the NO_x port admittances alone, without encountering combustion or flame instability or any other known problems. This approach, however, would be limited to NO values which are still fairly high (200 and 225 ppm for gas and oil fuels, respectively, in the H5/6 boilers) because of the relatively constant NO generation in the NO_x port mixing zone. As a single NO_x reduction technique, however, this would represent



(a) With natural gas fuel

Figure 2-11. Effects of combustion air diverted through NO_x ports (two-stage combustion)



(b) With low-sulfur oil fuel

Figure 2-11. Effects of combustion air diverted through NO_x ports (two-stage combustion) (Continued)

reductions of 69 and 47 percent for gas and oil fuels, respectively, from the uncontrolled levels, with no decrease in plant efficiency.

2.2.3.3 Excess Air

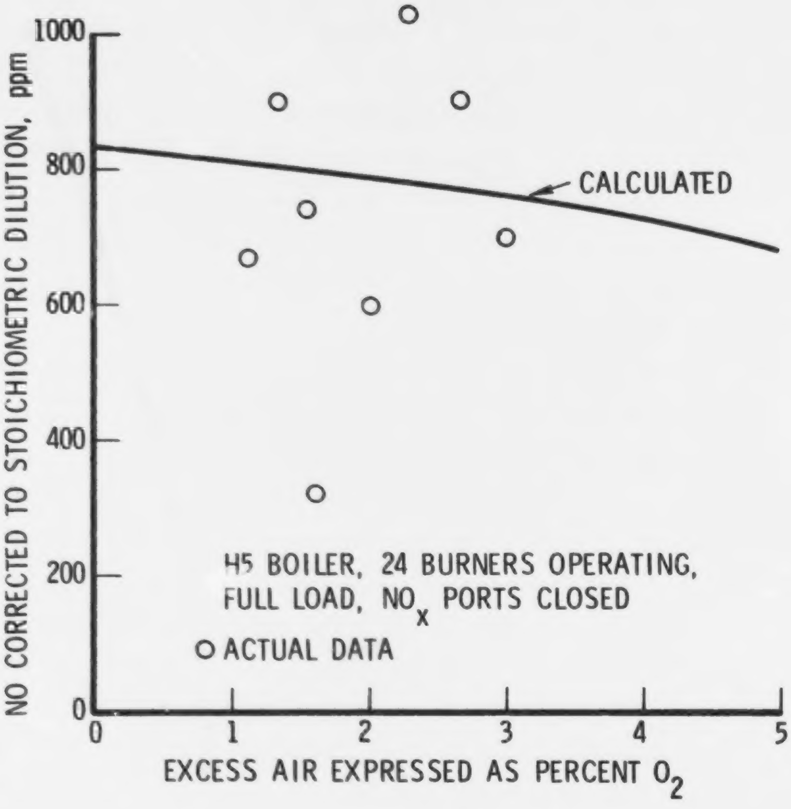
The interest in excess air variation as a NO_x reduction technique stems partly from the fact that low excess air improves plant efficiency. Since the minimum temperature of the flue gas entering the stack is limited by operational considerations, the less total flue gas flow or excess air leaving the boiler heat exchange surfaces at this temperature, the lower are the heat losses.

When the excess air is varied, part of the variation of measured NO concentration values is due to simple dilution of the NO by the excess air. Since it is actually the total NO_x being discharged to the atmosphere that is significant to atmospheric pollution, direct values of NO at the excess air level can be somewhat misleading. As a result, both the calculated and measured values of NO were corrected to those concentrations which would result if the same NO were diluted by the products of stoichiometric combustion.

Figures 2-12a and b show the results of these calculations for gas and oil fuels. The oil fuel calculation, as expected, shows a decrease in NO values with decreasing excess air but the magnitude of the reduction is only about 70 ppm over the full 5 percent O_2 range. The data available at the test conditions is minimal but tends to confirm both the magnitude of the NO calculation and the relatively flat slope (but not the positive slope). No evidence of excessive CO or smoke was indicated at any of the test conditions shown.

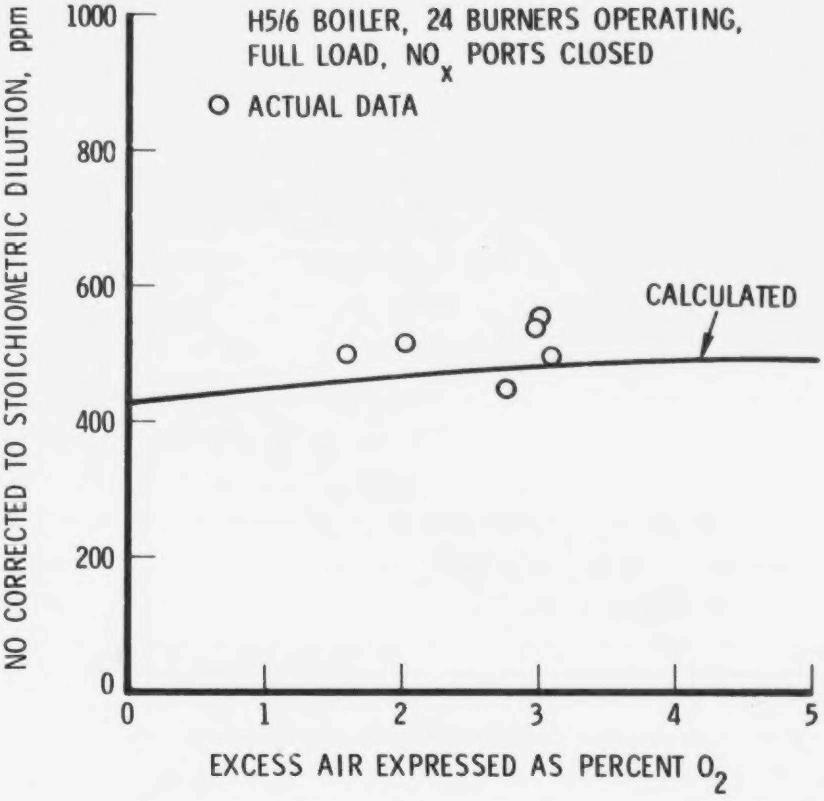
The gas fuel calculation, however, shows an increase in NO with decreasing excess air, of as much as 150 ppm over the 5 percent O_2 range. The little data available at these test conditions (all 24 burners operating, NO_x ports closed, and full load) is minimal and widely scattered. This wide scatter in measured NO data at these test conditions has been noted previously. The data shown generally support the magnitude of the calculated NO curve but cannot confirm or deny the calculated slope of the curve. Again, there was no evidence of CO or smoke problems over the range of O_2 data shown.

In general, Figure 2-12 tends to indicate that, at least under the operating conditions of those data and with little or no bound nitrogen in the fuels, reduction of excess air is not a particularly effective method of NO_x reduction nor does it significantly increase NO_x. It probably always improves plant efficiency. The general effect of reduction in excess air is to reduce the A/F ratio in all of the mixing zones and to decrease the total flue gas flow. Depending on many complex effects of these two simultaneous variations and on the amount of bound nitrogen in the fuel, it could be expected that NO could increase or decrease with excess air. Clearly, if a large part of the flow in the furnace spends considerable time at A/F ratios just above the range for high thermal NO generation rates, then a reduction in excess air could reduce the A/F ratio of these zones into this undesirable range, and an increase in thermally-generated NO_x emissions could result. In this respect, reduction in excess air would tend to increase NO_x emissions. Reduction in excess air, however, apparently always decreases NO arising from the conversion of fuel-bound nitrogen. A reduction of NO from this source could offset the increase in thermal NO and result in a net decrease in NO_x emissions with reduction in excess air. This explanation is consistent with the slopes of the calculated curves shown in Figure 2-12. A fuel containing large concentrations of bound nitrogen would be expected to exhibit a strong trend toward lower NO_x emissions with reduced excess air. For the fuels of this study, containing little or no bound nitrogen, the net effect of excess air is in all cases small.



(a) With natural gas fuel

Figure 2-12. Effects of excess air



(b) With low-sulfur oil fuel

Figure 2-12. Effects of excess air (Continued)

2.2.4 Burners-Out-of-Service (BOOS)

The final result of the parametric analyses of the correlation equations is the most important because, at present, it is only from data from full-scale multiple-burner boilers that insight into the effects of BOOS can be obtained. No configurations were tested in the H5/6 boilers with more than eight burners operated as air-only. With this many (Air) burners, and particularly with NO_x ports open, the burner A/F ratio with gas fuels becomes so low that combustion stability can become a problem, and the flame can move back deep into the burners, causing register overheating. Even limiting the number of (Air) burners to less than 9 in the total array of 24 burners, however, more than a million different arrangements of (F+A) and (Air) burners are possible. Several preliminary observations were necessary, therefore, to limit the configurations evaluated.

One observation is based on the earlier discussion of the time and space rates of mixing of the air and fuel, down to the molecular level, as shown schematically in Figure 2-4. This mixing can be considered to occur in two major phases: (a) within the flows from burners at a given level, with some mixing with the flow recirculated from the burners immediately below that level, and (b) between the burner flows and the bulk gases resulting from all of the burner flows below that level. If the average mixing at a given level is complete on a molecular scale before the flows enter the bulk gases, then the mixed A/F ratio would have already passed through the region of high NO generation rates. It would be desirable, then, to mix the flow from this level with bulk gases which are also at A/F ratios below the critical region to avoid again passing through this region until as much cooling as possible has occurred. This case suggests that all of the (Air) burners should be located at the top of the burner array or that only NO_x ports be used.

If, however, this molecular-scale mixing is far from complete before the flows from a given level begin strong mixing with the bulk gases, then it would be desirable to introduce (Air) burners at the lower levels so that the bulk gases are at A/F ratios above the critical range. The average molecular-scale mixed A/F ratio need never pass through stoichiometric and would only just enter the critical A/F ratio region after the maximum cooling has occurred. This case implies one or more (Air) burners at the lowest level in the furnace and no NO_x ports.

Even one (Air) burner at the lowest level (and no NO_x ports) will cause the bulk gas A/F ratio to start high and monotonically decrease to the overall boiler A/F ratio. Figure 2-5 shows a schematic of the variation of the bulk gas A/F ratio with furnace level, with just one (Air) burner located at various vertical levels. A single (Air) burner located at some midlevel causes the bulk gas A/F ratio to shift from below to above the overall furnace A/F ratio at that level. This latter location for an (Air) burner might be desired if the bulk gas spreading is such that mixing is essentially complete in the burner flows (before entering the bulk gases) below that level but is incomplete above that level. Thus, one aspect of (F+A) and (Air) burner configurations that appeared worth evaluating was the vertical level of the (Air) burners.

A second observation is based on the evaluation of the correlation equations themselves. In the H5/6 correlations, it was shown earlier that the first two terms in the correlation equations tend to dominate the NO_x variations, particularly with gas fuels. It was also shown in the parametric evaluations of the correlation equations that bypassing large fractions of combustion air through NO_x ports and, similarly, through (Air) burners is very effective in reducing NO_x emissions from uncontrolled levels but cannot reduce these emissions below still significant levels. Further, in the case of gas fuels, term 1, the primary region of (F+A) burners, has a negative coefficient. Thus, to get very low NO_x emissions, it seems desirable to maximize the number of (F+A) burners or minimize the number of (Air) burners and use no NO_x ports. Term 1 in the H5/6 correlation for oil fuels appears to indicate an opposite trend would be desirable, but the early mixing zones do not dominate this correlation as much as in the gas fuel case. In any case, the above considerations suggest that the effect of the number of (Air) burners in the array should also be investigated.

2.2.4.1 Effects of the Vertical Location of (Air) Burners

The effects of the vertical location of (Air) burners was first investigated with four and eight (Air) burners in the array. Other test conditions were (a) NO_x ports closed, (b) 3 percent O_2, and (c) full load. Figure 2-13 shows the values of NO calculated for the cases of four (Air) burners located at each of the six vertical levels for both gas and oil fuels. No data is available from tests of these boilers with four (Air) burners, so these calculations represent an interpolation between data involving either no (Air) burners or eight (Air) burners. The figure shows that the effects of the vertical location of four (Air) burners is opposite for gas and oil fuels. This was expected as a result of the opposite signs of terms 1 and 2 in the H5/6 gas and oil correlations.

The calculated values of NO for gas fuels with the four (Air) burners at all levels except the top are low and even negative when the (Air) burners are in levels 3 through 5. Obviously, negative values of NO are meaningless and may indicate that the range of interpolation between zero and eight (Air) burners is too large or that the true NO values would simply be zero. The general observations which appear reasonable from the gas fuel calculation, however, are (a) with NO_x ports closed, four (Air) burners appear to yield lower values of NO than either zero or eight (Air) burners, and (b) the (Air) burners should be located at the midlevels in the H5/6 boilers.

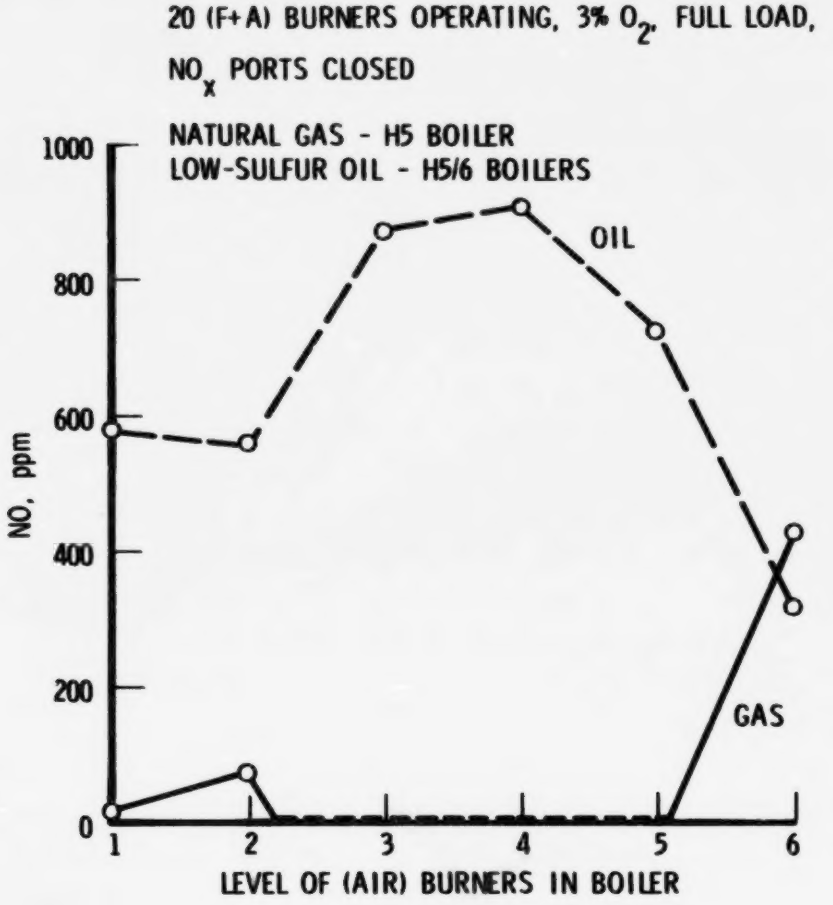


Figure 2-13. Effects of the vertical location of four (Air) burners (calculation only)

The oil fuel calculation in Figure 2-13 shows that all of the NO values except those calculated with the (Air) burners at the top level are higher than the calculated or measured data with either zero or eight (Air) burners in any configuration. Even the NO value calculated with the (Air) burners at the top level is not particularly low. The general observation from Figure 2-13 for oil fuels, therefore, is that four (Air) burners at any furnace level yield little, if any, advantage over other techniques to reduce NO_x.

The calculations for the case of eight (Air) burners indicated that the contributions of all terms upstream of the bulk gases were reduced essentially to zero. Of the remaining terms, only the NO from the bulk gas mixing zones is affected by variations in the vertical location of the (Air) burners. Figure 2-14 shows the calculated values of the bulk gas term (term 7) only as a function of the average vertical level of eight (Air) burners for both gas and oil fuels. As a direct result of the variation of the bulk gas A/F ratio with vertical location of (Air) burners, shown schematically in Figure 2-5, the value of the bulk gas term in Figure 2-14 is minimum when the (Air) burners are at the bottom or top levels for both gas and oil fuels. Both of these levels represent cases where the bulk gas A/F ratio does not enter the critical A/F ratio until maximum cooling has occurred.

Figure 2-15a shows the total calculated values of NO versus the average level of eight (Air) burners with the NO_x ports closed for the gas fuel data. The available data for these test conditions are also plotted for both open and closed NO_x ports. According to the previous discussion, when (Air) burners are located in the top levels, the bulk gas A/F ratio is below the critical A/F ratio range up to the top levels. Thus, open NO_x ports would only decrease the bulk gas ratio further below the critical range, with little further effect on NO_x emissions. Conversely, when the (Air) burners are located in the bottom levels, the bulk gas A/F ratio would remain above the

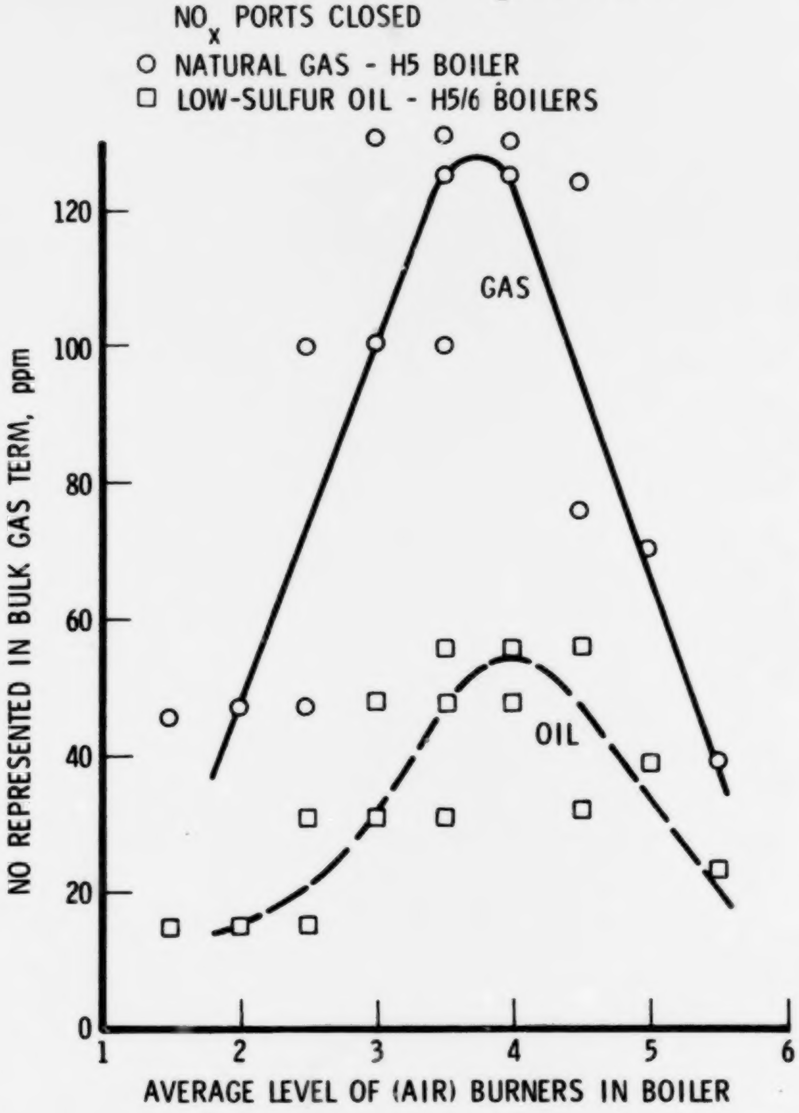
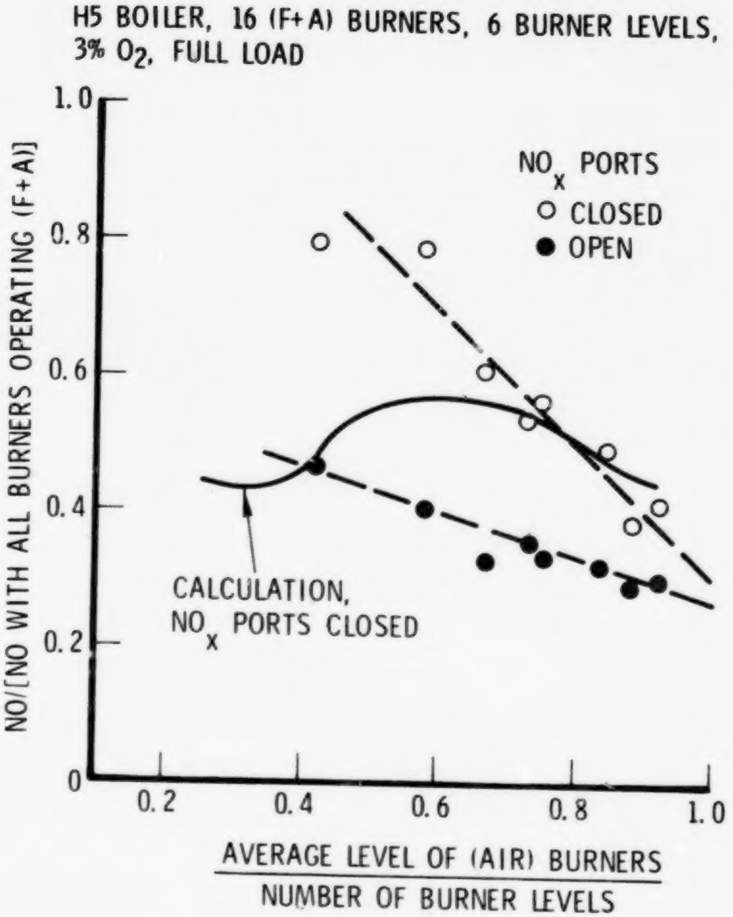
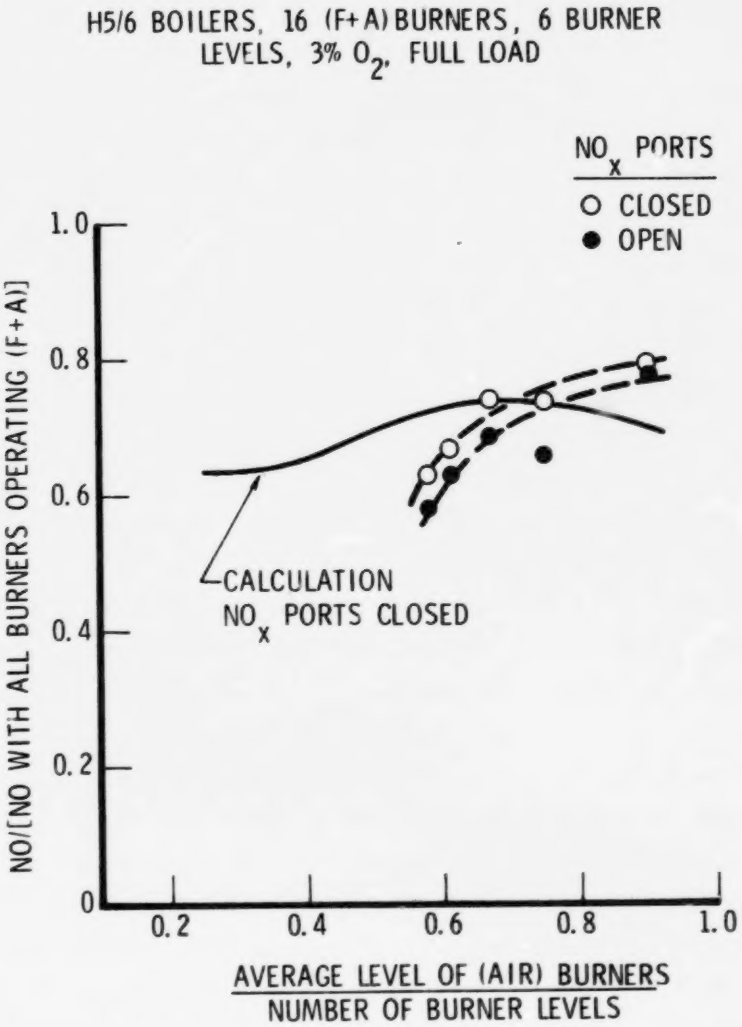


Figure 2-14. Effects of the vertical location of eight (Air) burners on the NO_x represented in the bulk gas term in the correlation equations



(a) With natural gas fuel

Figure 2-15. Effects of the vertical location of eight (Air) burners



(b) With low-sulfur oil fuel

Figure 2-15. Effects of the vertical location of eight (Air) burners (Continued)

critical range. Open NO_x ports in this case would reduce the bulk gas A/F ratios further, at least at the upper levels, into the critical range, causing the NO_x to increase. Figure 2-15a shows that when the eight (Air) burners are located in the top two rows: (a) NO_x emissions are minimum; (b) the data for NO_x ports closed agree well with the calculated values; and (c) the effect of NO_x ports open or closed becomes negligible. These data are in agreement with the above reasoning. Unfortunately, there are no data, at least in this data sample, in which the eight (Air) burners were located in the two bottom rows. However, the NO_x port open or closed data should reverse in this case, with the NO_x port closed emissions less than or at least equal to the NO_x port open data. The calculated values of NO (NO_x ports closed) indicate this trend in that they tend to decrease to the NO_x port open data or slightly below. Two NO_x port closed data points, however, disagree with the calculated curve. The data to confirm or deny the calculated NO values with the eight (Air) burners located in the lowest furnace levels are insufficient. It is clear, however, that minimum NO_x emissions with gas fuels at these operating conditions, using eight (Air) burners, are obtained with the (Air) burners in the highest burner levels, whether NO_x ports are open or closed.

Figure 2-15b shows the same kind of information as Figure 2-15a but for oil fuels. Here the agreement between the data and the calculated trends is poor. The calculated NO values indicate minimum NO with eight (Air) burners at either the lowest or highest levels but with only 42 ppm separating the minimum from the maximum. The data indicate an apparently strong trend toward a minimum with the eight (Air) burners located at the lowest level. With the (Air) burners located at the highest levels, however, the data trend is somewhat questionable. In the data available for (Air) burners located at average levels higher than the fourth, three data points show a continuing upward trend in NO_x, while a single data point, shown in the Figure 2-15b at the 0.75 level, indicates a decreasing trend. If this one measurement is ignored, however, the data trend indicating minimum NO_x emissions with eight (Air) burners located in the lower levels is clear and consistent. The NO_x data shown have a range of 94 ppm from minimum to maximum. In the case of oil fuels, the eight (Air) burners were never located lower in the furnace than an average level of 3.5 (equivalent to four (Air) burners in the third level and four in the fourth level). The calculated curve indicates that the trend toward decreasing NO_x with lower (Air) burner locations should reach a minimum at some level but there are no data available to indicate the value of that minimum level. The measured values of NO_x with the eight (Air) burners at the lowest average level tested were 239, 262, and 265 ppm. As discussed earlier, Ref. 2-2 indicates that at 3 percent O_2, conversion of the bound nitrogen in the fuel used in these boilers should yield about 222 ppm. This might be expected to represent the minimum NO_x value with the eight (Air) burners located low in the furnace, but the actual minimum level in the H5/6 boilers cannot be accurately predicted. Certainly, the decreasing trend indicated in Figure 2-15b shows no tendency to level off.

This result with oil fuels is entirely compatible with the earlier reasoning involving the time and space rate of molecular-scale mixing of the fuel with the air. It seems likely that the large oil fuel droplets generated by the oil guns in these boilers would not have completely evaporated by the time they enter and mix with the bulk gases. As a result, the A/F vapor ratio is probably above the critical A/F ratio range when this mixing begins to occur. The data indicate that in such cases the minimum NO_x emissions would be achieved by locating the (Air) burners in the bottom level of the furnace to keep the bulk gas A/F ratio also above the critical range. The minimum NO_x achieved in this manner, however, would be limited to that resulting from conversion of the bound nitrogen in the fuel at these relatively high A/F ratios. Attempting to keep the A/F ratios always low with existing hardware appears always to increase the thermal NO by more than the fuel NO is decreased, resulting in a net increase in NO_x emissions. Ultimate minimum NO_x emissions with oil fuels appear to require more radical hardware modifications.

2.2.4.2 Effects of the Number of (Air) Burners

The results of the studies on the effects of the vertical level of four and eight (Air) burners appear to establish the conditions for minimum NO_x with oil fuels within the constraint of existing hardware. The minimum condition for gas fuels has not yet been indicated. The results with four (Air) burners indicated that some number of (Air) burners between zero and eight, with the (Air) burners located at midlevels in the burner array and with no NO_x port flow, yields a minimum NO level. A further parametric run was made, therefore, to evaluate the variation in the number of (Air) burners located at midlevels and with no NO_x port flow. Figure 2-16 shows these results, along with the available data. In the calculation, (Air) burners were added, and (F+A) burners subtracted, one at a time to the fourth level of boiler H5 until that level was all (Air) burners. In the next step, all of the burners on level three were designated as (Air) burners, those on level four as (F+A), and the burners in level five as (Air) burners, one at a time, until a total of eight (Air) burners were included. The NO values calculated in this manner are represented in the curve in Figure 2-16 labeled "minimum calculated NO."

The curve in the figure shows a sharp drop to negative values in the calculated NO with the addition of only one (Air) burner in level four. The minimum NO appears to be reached at between two and three (Air) burners. NO values as low as -1550 ppm were calculated. The fact that negative NO values were calculated could indicate that interpolation between the data points at zero and eight (Air) burners

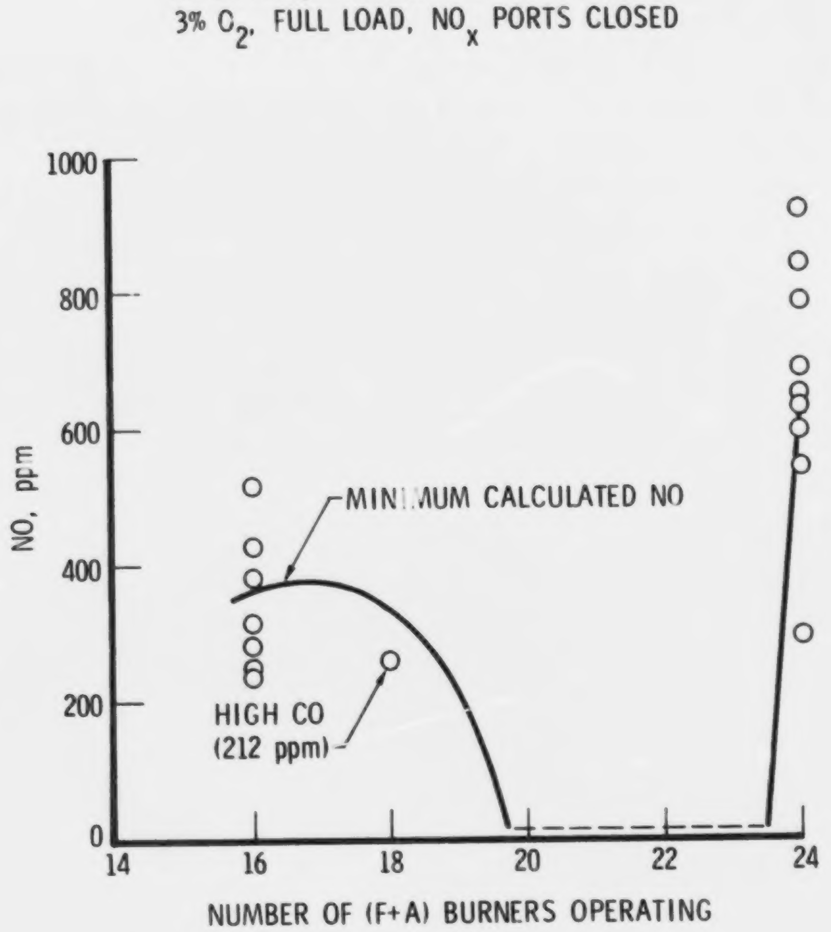

H5 BOILER, 24 BURNERS OPERATING, 3% O_2, FULL LOAD, NO_x PORTS CLOSED

Figure 2-16. Effects of the number of (Air) burners located at midlevels with natural gas fuel

is too great. Considering the large values for terms 1 and 2 in Table 2-7 and the extreme sensitivity of NO formation to temperature at the high temperature levels of this boiler at full load (570-degrees K or F combustion air temperature), it is not surprising that parametric calculations around these full load conditions are sensitive. A series of calculations similar to the series shown in Figure 2-13 for the gas fuel with the combustion air temperature reduced by only 30 degrees K (50 degrees F) completely eliminated all negative values of NO, but the minimum at midlevels remained. It seems clear that the actual magnitude of NO which might occur at the minimum in Figure 2-16 cannot be accurately predicted, but both the available data and the related reasoning indicate that such a minimum does exist.

As noted, the measured NO_x emissions in the H5 boiler under full load conditions with all burners (F+A) and the NO_x ports closed are extremely scattered. Figure 2-16 again shows such data. The data cover a range of 627 ppm, from as low as 292 to as high as 919 ppm, under supposedly identical test conditions in the same boiler. The data shown in Figure 2-16 for the condition with eight (Air) burners show that this variation cannot be ascribed to NO_x measurement error alone. The data points shown in Figure 2-16 for eight (Air) burners represent those obtainable within ±1 percent of the 3-percent O_2 excess air. Although these data include wide variations in the arrangement of the eight (Air) burners in the burner array, the total data spread is still only 280 ppm. A large part of the measured data variation for the condition with all burners (F+A) is considered real and due to the extreme sensitivity to temperature variations under these high-temperature conditions. Figure 2-5 shows that even one (Air) burner located in the top level of the H5/6 burner array can shift the A/F ratios of the remaining burners and the bulk gases very close to stoichiometric. In such a case, all of the burner flows and the bulk gas flows would remain at this very high NO_x generation rate A/F ratio throughout most of the radiant section of the boiler. Conversely, that same single (Air) burner located in the bottom level of the burner array would again shift the A/F ratios of the remaining burners near stoichiometric, but would also shift the bulk gas A/F ratios far above stoichiometric, at least until all burner flows are mixed into the bulk gases and considerable cooling has occurred. Inadvertent maldistribution in air flow to several burners in the same general vertical locations can accomplish these same effects. Considering the exponential effect of A/F ratio (through temperature) on the NO_x generation rate, it is easy to see how such maldistribution, under high-temperature conditions of the H5/6 boilers with all burners operating (F+A) and NO_x ports closed, can cause large variations in measured NO_x emissions under apparently identical operating conditions. Under any other off-stoichiometric or lower-temperature operating conditions, the effects of such maldistribution would be much less marked. The deliberate introduction of a single (Air) burner to the array, under the conditions where all other burners are (F+A) and the NO_x ports are closed, might be expected to result in dramatic changes in the NO_x emissions.

On the other side of the minimum shown in Figure 2-16, only one test condition could be found in which less than eight (but more than zero) (Air) burners were in operation. This was a test in the midst of a series evaluating the effects on NO_x of various arrangements of eight (Air) burners. Two (Air) burners were apparently restored to (F+A) for operational test purposes. The average vertical level of the six (Air) burners was that of the fifth level. Although the O_2 level was 2.53, CO was measured at 212 ppm, an excessively high level, and further testing of this configuration was terminated. The measured NO_x level of 261 ppm was the third lowest measured in any test with NO_x ports closed and under full load. Thus, this one test appears to lend support to the existence of a minimum NO_x level at some operating condition involving a number of (Air) burners between zero and six.

Also, from the earlier analyses of the correlation equation and the parametric studies of the effects of cooling rates, NO_x port flows, and combustion air temperatures, it appears likely that the molecular-scale mixing of the gas fuel into the combustion air in the burner flows does not approach completion until well into the secondary mixing zone. At about the fourth burner level in the furnace, the bulk gases have probably spread sufficiently that the burner flows issuing from the primary mixing zones at that level begin to mix directly with bulk gases before the molecular-scale mixing of the gas fuel and air can achieve the overall burner A/F ratio. The model (Figure 2-2), in fact, assumes that mixing in the secondary zones does not exist at all in the top level. It is precisely at the fourth level that this parametric study indicates that it is desirable to shift the bulk gas A/F ratio from a fuel-rich mixture, resulting from levels 1 through 3 flows, to an air-rich mixture for levels 4 through 6. It appears, then, that (Air) burners located in level 4 add further air to unmixed flows from the burners in levels 4 through 6 and avoid the critical A/F ratio range by keeping the average molecular-scale mixed A/F ratios above it.

As a result, it appears that a real NO_x minimum exists with gas fuels and should be reached by a burner configuration consisting of one to four (Air) burners located in the fourth level of the H5/6 boilers with NO_x ports closed. The magnitude of this minimum cannot be determined. The one data point available and nearest to this minimum condition exhibited high CO emissions. The reason for this is not known, nor is it known whether excessive CO will be a problem at the minimum NO_x condition. No other limiting problems were apparent.

2.2.5 Other Boilers

Most of the results discussed thus far were based on the correlations of gas-fired data from one of the two largest boilers in the data sample and oil-fired data from these two largest boilers combined. The reasons for this were (a) the unique opportunity to develop new understandings in this study concerning the effects of BOOS techniques on NO_x, (b) the need for a fairly large data sample on the exact hardware and operating conditions analyzed to evaluate the accuracy of the correlation equations in predicting the effects of single independent variables, and (c) the need for large numbers of test conditions covering wide ranges of the independent variables to obtain a good correlation equation. The first reason suggests that large boilers with large numbers of burners should be of primary interest. The second reason suggests limiting the detailed analyses to a single boiler if possible. The third reason, however, dictates that only the H5/6 data, both gas and oil firings represent samples large enough to obtain good correlations for a single boiler or boiler type. Table 2-3 shows that no more than 51 test conditions were available on any other single boiler type.

The approach taken to include the other boiler types in the correlations was to separately correlate the smallest useful data samples and then combine these until all gas data were included in one sample and all oil data in another. This resulted in the correlation of the data samples shown in Tables 2-5 through 2-7. Parametric calculations using correlation equations resulting from data from more than one boiler type could be made, which might indicate the effects of some of the independent furnace variables on NO_x. However, nearly a dozen independent variables are associated with a given furnace and only five different furnace types. Thus, unless many of these variables could be combined or eliminated, the interpretation of such parametric calculations could be very difficult. It was decided, therefore, to limit evaluation of the effects of furnace variables to observations on the various correlation equations themselves and on such data as were available, particularly in view of the conditions for minimum NO_x determined for the large boilers.

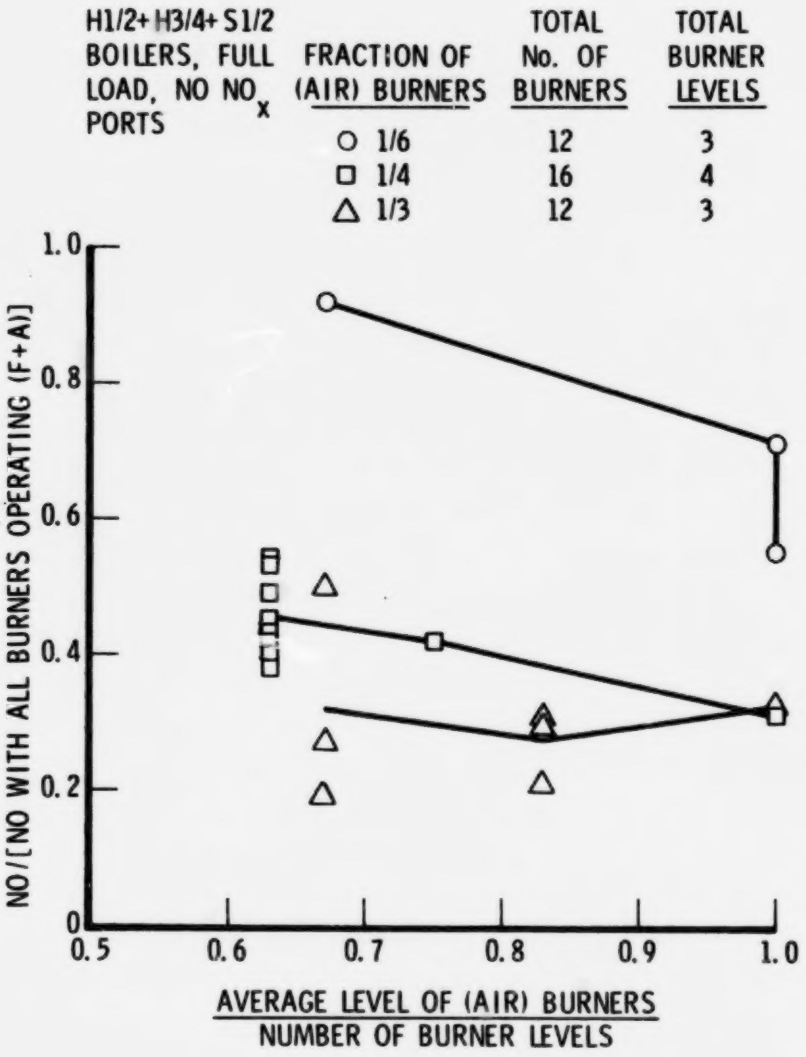
2.2.5.1 Natural Gas Fuel

For gas fuel, the general operating conditions for minimum NO_x in the large boilers involved a small number of (Air) burners at the midlevel in the furnace with no NO_x ports. This was generally conjectured from the correlation equation from the conditions necessary to maximize terms 1 and 5 and minimize term 2 (Table 2-7). The small number of (Air) burners was necessary to keep term 1 as large as possible, and (Air) burners located in the midlevels reduced term 2 as much as possible and left term 5 at its maximum. In all of the other correlations involving the small boilers with only three or four vertical levels, the signs of these three terms are the same but they are less predominant in determining total NO values compared to the bulk gas zone term 7. From considerations such as indicated in Figure 2-14, bulk gas zone NO contributions can be minimized by locating the (Air) burners at either the top or bottom levels. Also, term 4, associated with burner configurations involving an (Air) burner directly above an (F+A) burner, becomes relatively more important in the smaller boilers. This term is negative and, therefore, to maximize it the (Air) burners should not be located in the bottom level.

Thus, locating the small number of (Air) burners near or at the top burner levels would most likely lead to minimum NO_x in boilers with small numbers of vertical levels. This seems reasonable since, as the number of vertical levels of burners approaches zero, the furnace configuration approaches that of a single burner in which the distinction between burner flows and bulk gases disappears; i.e., all flows are essentially bulk gas flows. With single burners, the BOOS technique is meaningless, and only staged combustion is left as a technique to reduce NO_x.

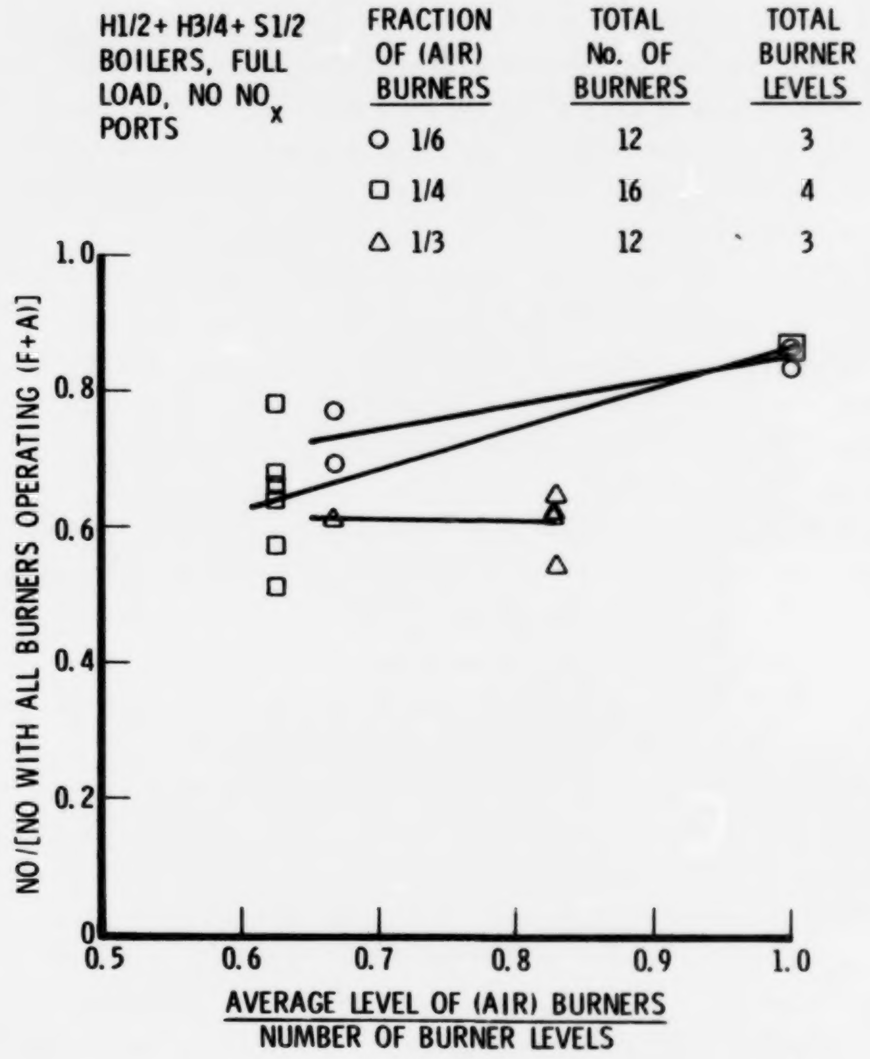
Figure 2-17a shows the available gas-fuel data, which justify these conclusions. With only 2 burners out of 12 (1/6) operating air-only, the effect on NO_x is small, but the reduction is greatest with the (Air) burners located at the top (third) level. Nearly all of the NO_x reduction is accomplished with between one sixth and one fourth of the burners operating air-only and with these (Air) burners located in the top level. Increasing the number of (Air) burners to one third of the total affects no further reduction with the (Air) burners located in the top level, but a tendency toward minimum NO_x with the (Air) burners located somewhat below the top level is indicated. This may simply be an indication that with four (Air) burners the whole top level of burners are (Air) and the second level is now top level. The NO_x minimum with gas fuel in the larger boiler was indicated with 1/24 to 1/6 of the burners air-only at the midlevels. With one third of the burners air-only, the location for minimum NO_x in the larger boilers shifted to the top row. Thus, the effect of reduced numbers of burners or reduced burner levels appears to be the elimination of the minimum, corresponding to a small number of (Air) burners at midlevel. Perhaps this is simply geometric, resulting from the fact that a clearcut midlevel does not exist in a boiler with a small number of burner levels and some (Air) burners.

In small boilers with small numbers of burner levels, the minimum NO_x appears to be achieved with a significant number of (Air) burners located at the top burner levels. Since all burner flows and bulk gases below the top level should contribute little to the total NO_x emissions in such a case, most must be generated when mixing of the bulk gases with the air flow from the (Air) burners causes the average molecular-scale mixed A/F ratio to cross the critical A/F ratio range. It would appear that if this mixing were delayed until further cooling of the bulk gases had taken place the NO_x emissions could be reduced. This implies, of course, a configuration involving no (Air) burners and instead NO_x ports of total admittance equivalent to the four (Air) burners placed well downstream from the top burner



(a) With natural gas fuel

Figure 2-17. Effects of the vertical level of (Air) burners in the smaller boilers



(b) With low-sulfur oil fuel

Figure 2-17. Effects of the vertical level of (Air) burners in the smaller boiler (Continued)

rows (at higher furnace levels). In the data shown in Figure 2-17a, only one of the boiler types (H3/4) had NO_x ports installed. The total admittance of these NO_x ports was estimated to be equivalent to only one (Air) burner. Thus, no data are available to test the effect of air flow equivalent to the total (Air) burner flows introduced further downstream.

From these considerations, it appears that the minimum NO_x conditions with gas fuels in the existing small boiler hardware (without introducing enlarged NO_x ports) have already been tested. With one third of the burners (Air), the possibilities of combustion, flame stability and excessive CO problems can become significant. Thus, the best condition for minimum NO_x appears to be with one sixth to one fourth of the burners (Air) and with these (Air) burners located in the top row. The two tests shown at roughly this condition in Figure 2-17a yielded 108 ppm in the four-level boiler (S2) and 140 ppm in the three-level boiler (H3). Opening the NO_x ports under the same operating conditions in the three-level boiler only reduced the NO_x to 135 ppm. In both of the cases in the three-level boiler with one third of the burners (Air), CO emissions were slightly high (58 to 87 ppm) even though the O_2 level was 2.78 to 3.65 percent. The single test in the four-level boiler with one fourth of the burners (Air) (4 of 16) also showed CO emissions of 60 ppm, but the O_2 level was significantly lower (2.15 percent). Thus, without major hardware changes, it appears that the NO_x emission minima for the three small boiler types in this data sample (S1/2 and H1 through H4) with gas fuels is in the range of 110 to 140 ppm. This should be sufficiently low to meet currently established regulations for the future.

2.2.5.2 Low-Sulfur Oil Fuel

In the analysis of the oil-fired data from the large boilers, it was concluded that the minimum NO_x condition in the existing hardware involved locating the (Air) burners in the lower levels of the furnace. This was interpreted as resulting from the fact that the molecular-scale mixing of the air and fuel vapor flow from the burners at all levels was not complete before forced mixing with the bulk gases occurred. Hence, it was desirable to maintain the bulk gas A/F ratio above the critical A/F ratio range to avoid passing through the critical range. The minimum NO_x level, then, should be that resulting only from conversion of the bound nitrogen at these fairly high A/F ratios. Attempting to keep the bulk gas A/F ratio below the critical range can reduce the bound-nitrogen conversion, but the data indicate (Figure 2-15b) that, at least in that boiler type, the increase in thermal NO generated in crossing the critical A/F ratio range more than offsets this reduction, resulting in a net NO_x increase.

In small boilers, with a small number of vertical burner levels, the A/F vapor mixing is still slow, but the distinction between burner flows and bulk gases becomes hazy. Using the same reasoning as before but treating the flows entirely as bulk gases, the minimum could occur under conditions maintaining the bulk gas A/F ratio either above or below the critical range, depending on the tradeoff between thermal NO_x generation rates and bound-nitrogen conversion efficiency. Lower combustion air temperatures or high cooling rates should reduce the thermal NO generation rates and should always favor the low bulk gas A/F ratio approach.

In the correlation equations in Table 2-7, a major difference between the large boiler correlation (H5/6) and those involving the smaller boilers is apparent. In the large boiler correlation, the dominant terms, as in the gas-fuel case, are again terms 1, 2, and 5. The signs of these terms are exactly opposite to those of the gas-fuel correlations. It is this difference in signs which leads to the nearly opposite conclusions regarding the best vertical locations for (Air) burners between gas and oil fuels in this large boiler type. In the small boiler correlations, Table 2-7 shows that with oil fuels, when the smaller boilers are correlated alone or included in significant numbers in correlations with the larger boiler type, the signs of these three predominant terms reverse and are the same as in the gas-fired case. As in the gas fuel case, these terms again become less dominant in the small boilers compared to the bulk gas term 7. There are no other significant changes in the oil-fuel correlations for smaller boilers compared to the larger (the sign reversal in the bound nitrogen and constant terms are considered meaningless) which might indicate the best vertical location for (Air) burners. On the basis of the similarity between the gas and oil data correlations for the small boilers, then, it would appear at first glance that a small number of (Air) burners located near or in the top burner row should yield minimum NO_x with these oil fuels.

Figure 2-17b shows the available NO_x data from the smaller boilers (H1/2 and S1/2) with oil fuels (full load and with no NO_x ports) plotted versus the average vertical level of the (Air) burners. Contrary to the initial guess, the trend, if any, appears to be opposite that of the gas-fired case and the same as in the large boiler type with oil fuels. The minimum NO_x condition appears to be attained with a small number of (Air) burners if they are located low in the furnace. The minimum which could be achieved with such a configuration should be the 222 ppm calculated earlier, from the data of Ref. 2-2, for the conversion of the bound nitrogen in the fuel to NO_x. The data in which 4 of the 16 burners were (Air) and the (Air) burners were located lowest in the furnace indicate an average of 173 ppm NO_x. The standard deviation of this small amount of data would easily include 222 ppm as a possible true value. The data where one third of the burners were (Air) indicate an average of 208 ppm, also very near the 222 ppm value. Thus, Figure 2-17b may indicate that a minimum of about 222 ppm, due only to conversion of the bound nitrogen in the oil fuel used, can be reached easily in these small boilers with a small number of (Air) burners located anywhere but at the top burner levels. With (Air) burners located in the top levels, the data indicate that the increase in thermal NO_x under these conditions begins to outweigh the reduction in bound-nitrogen conversion resulting from combustion at lower A/F ratios in more of the lower levels. Table 2-2 shows that the cooling factors for these smaller boilers are 1.3 to 2.2 times that of the larger boiler type, indicating that thermal NO_x should be less of a problem in these boilers.

Thus, it appears that with existing hardware, a minimum of about 220 ppm NO_x can and has been achieved in the smaller boilers, even with a small number of (Air) burners if they are located in the middle to bottom levels of the boiler. The tradeoff between thermal NO_x and that generated from the bound nitrogen in both the small and large boilers appears to be such that, with existing hardware, the minimum NO_x achievable is the limit set by the conversion of the bound nitrogen at about 3 percent O_2.

The frequent reference to the bound-nitrogen conversion efficiency implies that an estimate might be made of the effect of A/F ratio in the burners on this conversion efficiency. Such an estimate can be made from observations of the correlating equations. In the H5/6 correlation equation with oil fuel, as noted previously, the limits of NO_x for very low combustion air temperatures and for very high values of NO_x port admittance imply that (a) bound-nitrogen conversion with 3 percent O_2 in burner contributes about 210 ppm NO_x and (b) the NO_x port mixing zone contributes about 216 ppm thermal NO_x with large fractions of combustion air flowing through NO_x ports. Figures 2-8 and 2-6 show close approaches to these values at the limits of those calculations. With no air flow through the NO_x ports (Figure 2-6), the total calculated NO (427 ppm) should consist of 210 ppm from the bound nitrogen and 217 ppm thermal NO. Thus, the thermal NO at the limits of the calculation shown in Figure 2-6 in both cases is about 217 ppm. In between those limits it seems reasonable that the thermal NO could be larger than 217 ppm but unlikely that it would be smaller than this value. Thus, a conservative upper limit on the NO from the bound nitrogen can be estimated by assuming that the thermal NO over the entire range of Figure 2-6 is constant at 217 ppm. It is also reasonable to assume that the fuel NO thus calculated could never be larger than the 210 ppm at the burner A/F ratio corresponding to 3 percent O_2.

The results of this estimate are shown in Figure 2-18. The fuel NO drops rapidly with burner equivalence ratios (A/F) less than stoichiometric and begins to approach zero at equivalence ratios near 0.7. This equivalence ratio corresponds to an A/F of 9.7, which is approximately the rich limit for flame propagation with premixed natural gas fuels. If the fuel-rich products of liquid-oil combustion exhibit a similar fuel-rich flammable limit, then it is reasonable to assume that both the HC and the NO reactions might have difficulty propagating throughout the air-vapor fuel mixtures. This reasoning implies, therefore, that a reasonable estimate of fuel NO in fuel-rich mixtures might be a linear reduction from stoichiometric to zero at that burner equivalence ratio corresponding to the fuel-rich flammable limit of the air-vapor fuel mixtures.

2.3 FURTHER EXTRAPOLATIONS AND CONCLUSIONS

Throughout the analyses of the effects of various combustion modifications on NO_x from the available data sample, it

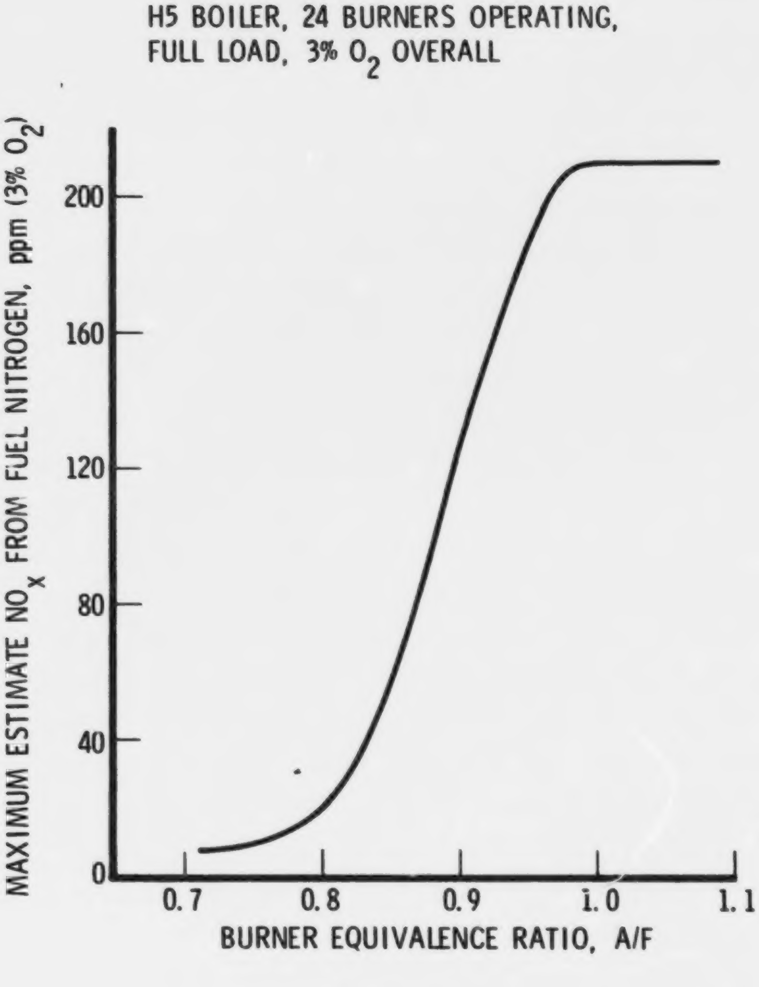


Figure 2-18. Maximum estimate of NO_x from fuel nitrogen versus burner equivalence ratio

appeared that all of the observed effects could be understood in terms of the probable time history of the average molecular-scale mixed A/F ratio. Particularly in the case of oil fuels, where the air-vapor fuel is the significant mixture, 90 to 95 percent of the total weight flow of reactants is represented by the combustion air. Buried in this large fluid flow is O_2, which is the ingredient necessary for the HC reactions as well as for the formation of NO_x. Large fractions of these reactions cannot occur until the 5 to 10 percent weight flow of fuel is mixed into this gross air flow on a molecular scale (i.e., fuel molecules near each and every O_2 molecule). Such mixing cannot occur immediately even with initially gaseous fuel. Some time and space is required for gross recirculation and eddies to dissipate into the small-scale isotropic turbulence approaching the molecular scale. This turbulence mechanism, or behavior, is discussed in Ref. 2-3. Consequently, in all cases, 90 to 95 percent of the total reactant weight flow enter the furnace from the burners at an infinite A/F ratio (pure air), and 5 to 10 percent enter at zero air-fuel ratio. While there are always interfaces between these two fluids where the molecular-scale A/F ratio is near stoichiometric, the fraction of the total weight flow involved in these interfaces is small until the scale of the turbulent mixing begins to approach zero. It appears, then, that the problem in controlling NO_x emissions can be thought of as one of controlling the fraction of the total weight flow of reactants involved in molecular-scale A/F ratios near stoichiometric and the time spent at these conditions.

Gross overall A/F ratios near stoichiometric can be tolerated for appreciable lengths of time if more air or fuel is mixed in before the major fraction of the flow begins to approach molecular-scale mixing. This case is approximated when the flow from a given burner enters (at right angles to) the relatively high-velocity fine-scale turbulent flow in the bulk gases in a large multiple-burner boiler.

Similarly, large fractions of the flow may be at small-scale A/F ratios near stoichiometric as long as continuing finer-scale mixing rapidly shifts the A/F ratio out of this region. This latter case is approximated by the relatively rapid mixing of gas fuels into the air flow from a given burner to arrive at a final, molecular-scale mixed A/F ratio well below stoichiometric. For short periods of time, large fractions of the air and gas fuel flow from a burner may be at small-scale air-fuel ratios near stoichiometric, but the continuing finer-scale mixing immediately reduces this ratio to well below stoichiometric. In the case of oil or coal fuels, this mixing through stoichiometric to lower A/F ratios is difficult to accomplish rapidly because the fuel vapor, or generated gases, is slowly bled into the surrounding air as the liquid fuel vaporizes or the coal gasifies, at least when the rates of these state-change processes are slow compared to the rate of turbulence decay in the gas stream.

2.3.1 Further NO_x Reduction Techniques

On the basis of these considerations, it is most desirable, from the standpoint of minimum thermal NO_x, to maintain the burner A/F ratios well above stoichiometric. Then, no matter how slow the turbulence decay or the rate of introduction of fuel vapor or gases, the average molecular-scale mixed A/F ratio need never pass through stoichiometric. In other words, the fraction of the total reactants near stoichiometric A/F ratios in the interfaces between gross unmixed regions of air and fuel will continually decrease with time as the turbulence decays and the mixing approaches molecular scale. Since the overall boiler A/F ratio is always maintained somewhat above stoichiometric (10 to 20 percent excess air) to assure complete oxidation of CO and other carbon and HC species, stoichiometric A/F ratios need not be crossed even at the boiler exit.

Such an approach appears to provide the best opportunity to reduce thermal NO_x to a minimum near zero. For fuels containing little or no bound nitrogen, this appears to be the simplest technique to apply to existing boilers for ultimate minimum NO_x emissions. Seemingly, the most direct hardware approach would be to incorporate fuel NO_x ports. All of the existing burners could be made air-rich by reducing the fuel flow to the burners, with the excess fuel added well downstream in the fuel NO_x ports. The same goal might also be accomplished by biasing the top row of burners to fuel-rich, leaving all of the lower burners air-rich. A gross approach to this goal, which has been tested in some boilers, is to simply shut the fuel off in some of the low-level burners in the boiler. The risk in this approach is that some or all of the flows from the resulting fuel-rich burners at higher levels may achieve average molecular-scale mixing to A/F ratios below stoichiometric before beginning mixing with the excess air from the (Air) burners below. This A/F ratio would then have to first decrease through stoichiometric in the burner flows and then increase through it again as the excess air is mixed in. Apparently, this is exactly what happens in current boilers firing natural gas fuels.

This approach to ultimate NO_x reduction is not particularly applicable with fuels containing bound nitrogen. It is well known that the efficiency of conversion of bound nitrogen is a function of the molecular-scale A/F ratio. If that A/F ratio is deliberately maintained above stoichiometric to minimize thermal NO_x, the conversion of bound nitrogen to NO_x would be very efficient. In the case of a fuel containing significant concentrations of bound nitrogen, then, the ultimate combustion modification technique to minimize NO_x emissions appears necessarily to involve maintaining a molecular-scale A/F ratio well below stoichiometric, at least until the nitrogen in the fuel has been converted to free molecular nitrogen. No other method of preventing the conversion of bound nitrogen to NO_x is known at this time. Some preliminary parametric studies of a correlation equation for the oil fuels used in this study (0.24 weight percent bound nitrogen) indicate that with sufficiently low burner A/F ratios resulting from large air flows diverted through NO_x ports, the NO_x generated from the bound nitrogen could be reduced to less than about 10 ppm.

A major problem with the fuel-rich burner technique for minimizing NO_x from fuel-bound nitrogen is to avoid the formation of thermal NO_x. As discussed, when burners are operated fuel-rich the molecular-scale mixed air-vapor fuel ratio of a large fraction of the reactants must decrease through stoichiometric to the low value during the decay of the large-scale induced turbulence (i.e., the fraction of the total reactants near stoichiometric in the interfaces between unmixed air and fuel must first increase to a maximum and then decrease to zero as the mixing approaches uniformity on a molecular scale). Unfortunately, those fuels containing high levels of bound nitrogen, such as oil and coal, are normally in the liquid or solid state. Otherwise, the nitrogen could be easily removed before burning. Thus the rate of mixing of the fuel vapor, or fuel gases, with the combustion air is usually controlled by the rate of vaporization or gasification of the fuel and not by the decay of the gross turbulence in the air. The mixing of the last fuel to be vaporized or gasified could, in fact, be reduced further because the turbulence in the surrounding air has by then decayed to fine scale.

One simple way to accelerate the initial air-fuel vapor mixing, of course, might be to atomize oil fuels to very fine droplet sizes. At some small droplet size, the vaporization rate would cease to be limiting on the air-fuel mixing rate, and oil combustion would start to behave like that with gas fuels. For further reduction of thermal NO_x, it might also be desirable to promote finer-scale more intense turbulence in the burner air flow. Oil fuel handling systems in current boilers provide oil pressures up to 1000 psi in the oil guns.

This energy should be adequate to finely atomize the oil with little or no increase in energy requirements on the plant. Pulverizing coal to very fine particle sizes may be more difficult and expensive in terms of energy demands on the plant; this area will be investigated in a later study. In the final mixing region, the molecular-scale mixed A/F ratio of the total boiler flow must once again be driven (rapidly) through stoichiometric when the final excess air is added (through NO_x ports, for example), but care should be taken to assure adequate cooling of the flue gases before this mixing is attempted. Many other methods of reduction of thermal NO_x, such as FGR through the burners, reduced combustion air temperatures, or water sprays in the combustion air, could be employed to assure minimum thermal NO_x formation in the discussed configuration, but these appear to require greater structural modifications than the approach described or could involve significant plant efficiency losses. Such techniques might be required in burning coal fuels, however. Existing hardware in current gas- and oil-fired boilers appear to be such that neither of the combustion modification techniques discussed provide minimum NO_x emissions. Minimum NO_x, in fact, is apparently achieved in the boilers studied here by almost exactly opposite techniques.

2.3.2 NO_x Minima with Existing Hardware

In the case of gas fuels, the existing NO_x ports are not readily adaptable to conversion to fuel NO_x ports. The secondary approach of limiting the air flow to the top row of burners to bias this row to fuel-rich and all the others to air-rich could be accomplished by reducing the flow area in the air registers in the top row. This reduction in air flow, however, could lead to combustion and flame stability problems in those burners, without a simultaneous and somewhat empirical redesign of the gas spuds. In any case, no test data are available under conditions even close to these two approaches to minimum NO_x. The air-rich primary, fuel-rich secondary type of reversed two-stage combustion with gas fuels, perhaps, should be evaluated first in single-burner laboratory furnaces for other undesirable side effects.

The data in this study, with gas fuels, indicate that complete, molecular-scale mixing of the air and gas is achieved rapidly in the burner flows but still requires significant time and distance in the furnace. In the large boiler type with six burner levels, it appears that this burner flow mixing is complete before mixing with the bulk gases begins for the lower three burner levels but is not complete in burner levels five and six. It would appear desirable to maintain the bulk gas A/F ratio well below stoichiometric for the first three burner levels but well above stoichiometric in levels five and six. This can be accomplished by locating a few (Air) burners in the fourth burner level with no NO_x port flow. Since such a configuration has not been specifically tested in these boilers, the parametric calculations using the correlation equation represent a rather large interpolation between existing data. The calculation, however, indicates the existence of a minimum in NO_x emissions with this burner configuration which could be very low, even approaching zero NO_x. The small amount of appropriate data available appears to confirm the existence of a NO_x minimum at these conditions but cannot suggest the value of that minimum. Although the reason is not apparent, some data indicate a potential high CO emissions problem in this configuration. There should be no problem of combustion or flame stability in this configuration.

In gas-firing in the smaller boilers with smaller numbers of burner levels, the separation of burner flow mixing from bulk gas mixing becomes somewhat academic, since the flow configuration begins to approach that of a single burner (i.e., the burner flows and bulk gas flows become in series or are one and the same). In this case, minimum NO_x appears to result with the simple two-stage combustion technique, and the BOOS technique becomes meaningless. The data from these smaller boilers indicate that with existing hardware minimum NO_x with gas fuels is achieved either by locating a relatively larger number (more than in the larger boiler type) of (Air) burners in the highest levels or by using few or no (Air) burners and large NO_x port air flow. These conditions have already been tested in the three smaller boiler types and yield NO_x minima in the range of 110 to 140 ppm. Some indications point to possible CO and combustion and flame stability problems if large fractions of air flow are diverted through (Air) burners or NO_x ports, but such large flows do not appear necessary to reach the NO_x minima. The data correlations tend to indicate that (Air) burners located in the bottom levels even in these smaller boilers cannot provide the reversed two-stage conditions discussed and that NO_x emissions in such a case would be higher than the 110 to 140 ppm range. No data is available to confirm this latter observation.

With gas fuels, short-term minima involving no significant hardware modifications required combustion modifications which are nearly exactly opposite to those which can achieve further reductions over the longer term. These short-term minima, however, represent large reductions in NO_x from uncontrolled levels and could satisfy even the stringent Los Angeles Air Pollution Control District (APCD) Rule 68 regulations for the immediate future. It is unlikely that the longer-term modifications, or even the possibly dramatic but simple tests in the larger type boiler, will be accomplished soon because of the phasing out of natural gas fuels in utility boilers. Such verification may become increasingly important in the longer term, however, if low-Btu gas from coal becomes a significant fuel in utility boilers.

In the case of oil fuels, the data appear to indicate that the vaporization of the liquid droplets in the furnace is sufficiently slow that the molecular-scale mixed air-vapor fuel ratio does not, at any burner level in any boiler, begin to approach levels below stoichiometric before mixing with the bulk gases (the flows from lower burner levels) begins to occur. Minimum thermal NO_x must then be attained by maintaining the bulk gas A/F ratio above stoichiometric. This, of course, leads to high efficiency of conversion of the bound nitrogen in the fuel to NO_x. Two NO_x minima are possible: (a) In the case where the thermal NO_x is minimized but the bound nitrogen conversion is high, and (b) in the case where the bound nitrogen conversion is minimized but the thermal NO_x is high. With existing hardware, the possibility of minimizing both sources of NO_x simultaneously appears to be unlikely. Thus, the only concern is which of these two minima is the lower. In the boilers studied here, the lower minima occur for the case where the thermal NO_x is minimized. The minimum NO_x achieved with oil fuels in the existing hardware studied here is specified by that value resulting from conversion of the bound nitrogen in the fuel at about 3-percent O_2. If 100 percent of the nitrogen in the fuels used in this study (0.24 percent by weight) were converted to NO_x at 3-percent O_2, a concentration of 353 ppm would result. The available literature indicates that for a fuel with 0.24-percent nitrogen, the conversion efficiency should be about 63 percent at 3-percent O_2. Thus, the minimum NO_x level in the hardware of this study should be about 220 ppm. All of the oil-fired data in the sample of this study indicated minimum NO_x values very near to 220 ppm.

These minima were achieved with a small number of (Air) burners located low in the furnace and with no NO_x port flow. No significant problems of CO emissions or combustion or flame stability were apparent at these minima, and no sacrifice of plant efficiency was apparent. As with the gas fuels, these minima still represent significant reductions from uncontrolled levels and appear to satisfy the stringent Los Angeles APCD, Rule 68, NO_x emission requirements scheduled for the near future. Where testing at the conditions for this minimum have not already been accomplished, it appears that such testing will be conducted in the near future.

To generalize these conclusions to apply to other existing boilers with oil fuels containing different concentrations of bound nitrogen is somewhat risky. The question of the appropriate firing configuration to achieve the lower of the two NO_x minima depends on the relative values of thermal and fuel nitrogen NO_x under these firing conditions. In plants firing high nitrogen oil fuels in boilers with large cooling rates, low combustion air temperatures or FGR, the fuel nitrogen NO_x may outweigh the thermal NO_x. In such cases, the opposite configuration from that indicated by the data of this study may yield the lower minimum (i.e., (Air) burners high in the furnace or NO_x ports). The smaller boilers in this sample with cooling rates 1.3 to 2.2 times higher than that of the larger boiler type indicate a trend in this direction.

The amount of fuel nitrogen NO_x generated is not a linear function of the weight percent of nitrogen in the oil at the same excess air. The literature indicates that the conversion efficiency of this nitrogen to NO_x decreases with increasing concentrations of nitrogen in the fuel. Thus, increasing the nitrogen in the fuels of this study from 0.24 weight percent, for example, by a factor of two (to 0.48 percent) only increases the NO_x resulting from this conversion from 222 ppm to 297 ppm, a factor of only 1.34. This level, however, may not meet emission requirements, and the minimum NO_x conditions indicated by APCD, for the oil fuels of this study, may not be acceptable. Thus, when oil fuels contain significantly more than the 0.24-weight-percent nitrogen the other minimum condition may have to be accepted, and more drastic measures may be needed to reduce the thermal NO_x.

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SECTION 3

COMBUSTION AND FLAME INSTABILITIES

One of the undesirable side effects of certain combustion modifications for the purpose of reducing NO_x emissions from utility boilers is the occurrence of various types of flame and combustion instabilities. These instabilities appear to be among those problems which limit the application of certain combustion modification techniques for NO_x reduction. If a general type of solution could be obtained for these problems, it may be possible that these combustion modification techniques might be extended to the point where future regulations could be met. The literature (Ref. 2-3) indicates that a wide variety of mechanisms could possibly explain the numerous types of flame and combustion instabilities observed in boilers, including both the feedback-coupled and the uncoupled varieties. If this is true, solutions to stability problems may be unique to each boiler.

In the current study, the effort in the area of flame and combustion instabilities was limited to a study of instability data in the sample obtained for the main (NO_x reduction) analysis. The purpose was to determine if a mechanism or mechanisms for the observed instabilities could be discovered and verified by the data. If this could be accomplished and the resulting mechanism was sufficiently general to be widely applicable, then actual analysis and/or modeling of that mechanism would be conducted at a later date.

This limitation, of course, implies that no new mechanisms could be generated and that the data would have to be examined in the light of known mechanisms. Few well developed analyses of instability mechanisms in the utility boiler literature were found, as compared with an abundance of data and analyses in the air-breathing engine and rocket engine fields, particularly, in the latter. Initially, then, the data were examined with respect to appropriate mechanisms developed for rocket engine applications. It is concluded here that the observed combustion instability data do verify a common rocket engine mechanism and that the flame instability data correspond to a nonlinear part of that mechanism.

3.1 FEED SYSTEM COUPLED COMBUSTION INSTABILITY

The combustion instability data obtained from the boilers studied occurred exclusively when natural gas fuel was in use. Therefore, the most destructive and widely studied mechanism of combustion instability in liquid rocket engines, the liquid-droplet combustion coupled mechanism, would not apply. Occurring more frequently but less destructively in rocket engines, including those engines where one or both of the propellants are injected in the gaseous state, is the feed system coupled mode of instability. This basic mechanism exists and provides a source for potential combustion instability in continuous combustion devices of all types. Instabilities of this general type have been involved in combustion instability problems in the development stages of nearly all liquid rocket engines and have occurred frequently in air-breathing turbine engines and even in solid rocket motors, although the feed system must be defined rather loosely in the latter case.

All continuous combustion systems require continuous feed of fresh reactants into a flame zone, as well as continuous discharge of exhaust products. All that is required to develop a classical feed system coupled instability is (a) a finite time delay from the time that reactants enter the combustor until a significant portion of those reactants are reacted (combustion time delay) and (b) a feedback coupling of the dynamic flow and combustion in which the gain (the amplitude of one cycle compared to the previous cycle) around the whole closed loop is greater than one at the frequency of the loop. The gain of the loop is frequency-dependent. The frequency of the loop is dominated by the combustion time delay. Both the variation of the gain with frequency and the combustion time delay are usually poorly known and, in any case, are specific to the combustor. For these reasons, exact solutions to feed system coupled instability problems in one combustor cannot normally be generalized to other combustors. One combustor might be stabilized by changing the combustion time delay and the loop frequency so that the loop gain at the new frequency is less than one (phase stabilization). Since the gain in another combustor may be a different function of frequency from the first, such a loop frequency change may not have the same effect on stability in the second combustor. In the latter case, the system might have to be stabilized by increasing the oscillatory energy dissipation in the components involved in the loop, thereby decreasing the loop gain to less than one at the same loop frequency (gain stabilization).

3.1.1 Gain Stabilization

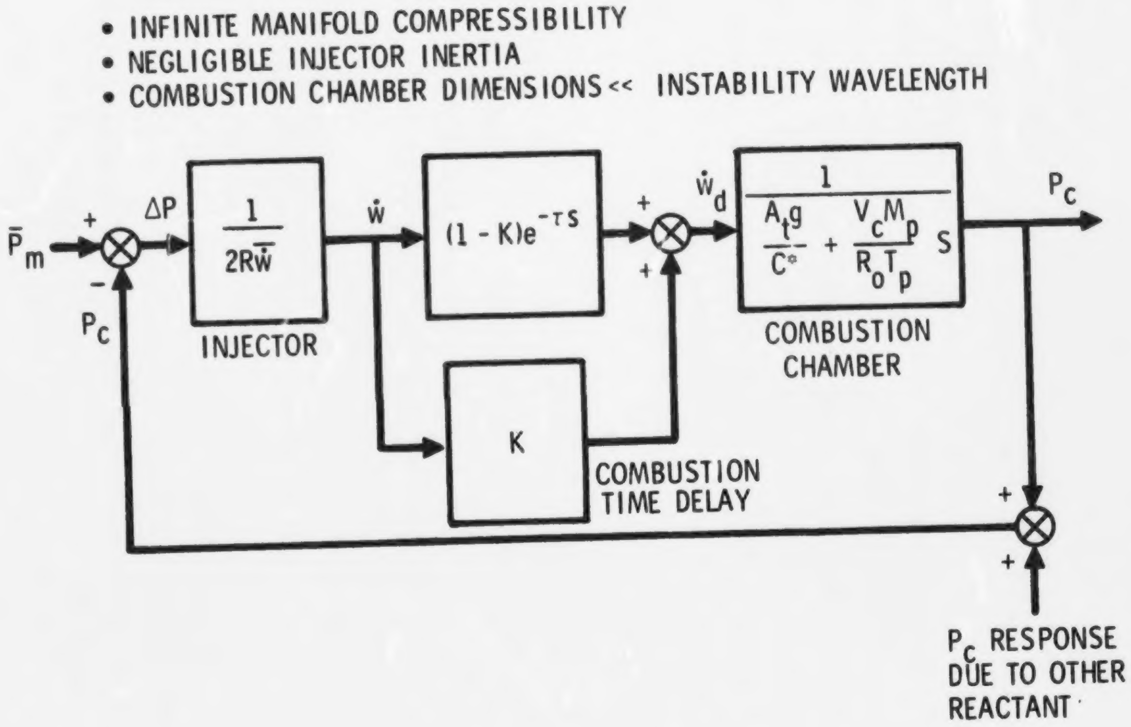
Although the general mechanism of feed system coupled instability is well known and has been analyzed extensively in rocket engine applications (Ref. 3-1), exact solutions for stability are usually difficult and specific to hardware. An asymptotic case can be established, however, which can lead to general design criteria for feed system stability. The hardware configuration for this asymptotic case in a liquid rocket engine is one in which the reactants are fed into the combustor from a large reservoir, through a number of short ports of negligible inertia, into a choked combustor of dimensions that are small compared to the wavelength of the oscillation. The latter criterion is satisfied at very low frequencies in any combustor. Such a system is shown, modeled in block diagram form in Figure 3-1. The general linearized equation for the loop gain of such a system (Ref. 3-2) shows a number of frequency-independent and frequency-dependent terms. As the loop frequency approaches zero, however, all of the frequency-dependent terms approach one, and the loop gain approaches a maximum. Thus, if this maximum gain for this most unstable feed system coupled loop can be made to be less than one, then the loop gain at any other frequency or in any other combustor configuration must also be less than one. Such systems would, therefore, be stable in feed system coupled modes of instability at all frequencies and with all other combustor configurations at the same operating conditions. Satisfying this criterion is called gain stabilization.

Since the gain inherent in the combustion itself and in the combustor pressure feedback path are difficult or undesirable to change, the gain stabilization criterion is applied to the pressure drop which causes the reactant flow into the combustor. This pressure drop is a resistance term in the analysis and tends to dissipate oscillatory energy and to reduce the loop gain. Higher pressure drops are stabilizing. For a rocket engine injecting both reactants in the gaseous state, the gain stabilization criteria for the two reactants are

$$\text{Air:}\quad \overline{\Delta P}_a > \frac{1}{2}\,\overline{P}_b\left(\frac{\overline{r}}{1+\overline{r}}\right)\left(1 - 2\,\frac{\rho_p}{\rho_a}\right) \qquad (3\text{-}1)$$

$$\text{Fuel:}\quad \overline{\Delta P}_f > \frac{1}{2}\,\overline{P}_b\left(\frac{1}{1+\overline{r}}\right)\left(1 - 2\,\frac{\rho_p}{\rho_f}\right) \qquad (3\text{-}2)$$

Gain stabilization criteria such as shown in Eqs. (3-1) and (3-2) have been derived and recommended for liquid rocket engines of various types since 1951 (Ref. 3-3) and were recently modified for



• INFINITE MANIFOLD COMPRESSIBILITY
• NEGLIGIBLE INJECTOR INERTIA
• COMBUSTION CHAMBER DIMENSIONS << INSTABILITY WAVELENGTH
$\bar{P}_m$
+
−
ΔP
P_c
$\frac{1}{2R\bar{\dot{w}}}$
INJECTOR
$\dot{w}$
$(1 - K)e^{-\tau s}$
K
COMBUSTION TIME DELAY
+
+
$\dot{w}_d$
$\frac{1}{\frac{A_t g}{C^*} + \frac{V_c M_p}{R_o T_p} S}$
COMBUSTION CHAMBER
P_c
+
+
P_c RESPONSE DUE TO OTHER REACTANT

Figure 3-1. Block diagram of a feed system coupled mode of instability in a rocket with gaseous reactants

the case of rocket engines with gaseous reactants (Ref. 3-2). These criteria are recommended in Ref. 3-4 for designing stable combustion into rocket engines. Reference 3-4 also indicates that, since the gain stabilization criteria may represent a "worst-worst" case, the pressure drops indicated by Eqs. (3-1) and (3-2) might be overly conservative. In liquid rocket engine history, feed system stability problems seem to have been absent if the feed system pressure drops were greater than about one half of those values. It can generally be expected, however, that if pressure drops are allowed to decrease to much less than half of the theoretical gain stabilization values, then feed system coupled instabilities might be expected. Thus, these criteria provide both an initial safe-design starting point and can be used as an indicator of when an observed instability is likely to be of the feed system coupled variety. This latter application was used in this study to evaluate the potential for feed system coupled instability in the utility boilers studied.

3.1.2 Gain Stabilization Applied to Utility Boilers

Because of the limited scope of investigation of combustion stability in this study, no attempt was made to derive gain stabilization criteria specifically for utility boilers. The only difference would be in the pressure response of the combustor. The exhaust flow in a rocket is determined by choked flow conditions in the nozzle, while the boiler flue gas flow is not choked. It is expected that the rocket case would yield higher response than that of the boiler, so direct application of Eqs. (3-1) and (3-2) to boilers would at least be conservative.

Most boilers operate at mean pressures in the boiler ($\overline{P}_b$) near 1 atm. The mean, overall weight A/F ratio ($\overline{r}$) is normally about 16. Because of the dominance of the nitrogen in the air and in the flue gases, the molecular weights of the combustion products are nearly that of air. The molecular weight of the natural gas fuel used in the boilers studied was 18.4. The density ratios in Eqs. (3-1) and (3-2) are given by

$$\text{Air:} \quad \frac{\rho_p}{\rho_a} = \frac{Mp\ Ta}{Ma\ Tp} \cong \frac{Ta}{Tp} \qquad (3\text{-}3)$$

$$\text{Fuel:} \quad \frac{\rho_p}{\rho_f} = \frac{Mp\ Tf}{Mf\ Tp} \cong 1.58\ \frac{Tf}{Tp} \qquad (3\text{-}4)$$

The temperature of the combustion products for a range of A/F ratios around the overall boiler ratio is about 2300 degrees K (3700 degrees F). For the data analyzed in this study, the combustion air temperatures were about 560 degrees K (550 degrees F) and that of the fuel was estimated to be near ambient (300 degrees K). Therefore, the approximate density ratios for the boilers studied are

$$\text{Air:} \quad \frac{\rho_p}{\rho_a} \cong 0.244 \qquad (3\text{-}5)$$

$$\text{Fuel:} \quad \frac{\rho_p}{\rho_f} \cong 0.206 \qquad (3\text{-}6)$$

With these data inserted into Eqs. (3-1) and (3-2), the pressure drops across the burners and gas spuds required to establish theoretical gain stabilized feed system coupled modes are

$$\text{Air:} \quad \overline{\Delta P}_a \cong 248\ \text{gm/cm}^2\ \text{(98 in. of water)} \qquad (3\text{-}7)$$

$$\text{Fuel:} \quad \overline{\Delta P}_f \cong 17.8\ \text{gm/cm}^2\ \text{(7 in. of water)} \qquad (3\text{-}8)$$

In large utility boiler common design practice, pressure drops across the gas fuel spuds or rings are normally quite large, in order to promote mixing of the small weight flow of fuel with the large weight flow of air. Thus gas-fuel pressure drops tend to be of the order of 1000 to 1800 gm/cm^2 (400 to 700 in. of water or 15 to 25 psi), well above even the most conservative estimate of that necessary for gain stabilization of fuel feed system coupled instability. In oil-fired units, the theoretical gain stabilization criterion is higher, about 30 gm/cm^2 (12 in. of water), but the fuel pressure drop necessary to atomize and distribute the heavy liquid fuel is very large, approaching 7×10^4 gm/cm^2 (1000 psi). Thus, fuel feed system coupled combustion instability should not be a problem in gas- or oil-fired utility boilers.

Such is not the case, however, with air feed system coupled instability. Because such large quantities of air must be pumped through the boiler (16 times as much as the fuel), the pumping energy requirements become significant in the overall plant efficiency. As a result, pressure losses in the air feed system tend to be minimized. Typical air pressure drops across the burners in the data studied are less than 25 gm/cm^2 (10 in. of water) at full load. This is less than 10 percent of the theoretical gain stabilization requirement indicated in Eq. (3-1). Even reducing the gain stabilization requirement to eliminate all of the conservatism discussed above, the actual air pressure drops appear to be well down into the range where air feed system coupled instabilities could be expected. In fact, the question appears to be one of why there are not more combustion instability problems with all boilers firing air, oil, or coal.

Probably, air feed system coupled instabilities were encountered in the initial development of the burners for these boilers, which were perhaps empirically stabilized by the manufacturers. The resulting system, however, should be classified as phase stabilized. As discussed, a phase stabilized system is stable only under certain operating conditions and can become unstable as a result of perhaps minor changes in these conditions, even though the hardware is the same. As long as the boiler is operated as designed, no stability problems should occur.

In recent years, however, existing boilers have been subjected to a wide range of user onsite modifications for the purpose of reducing NO_x emissions. NO_x ports have been added which remove air flow from the burners to implement the two-stage combustion NO_x reduction technique. Fuel flow has been turned off in some burners and diverted to the remaining burners to implement the NO_x reduction technique variously called "off-stoichiometric," "biased-firing," or "burners-out-of-service (BOOS)." Combustion air temperatures have been lowered, water has been sprayed into the combustion air, and other diluents have been added to it. Many of these changes affect the combustion time delay and thereby the loop frequency and phase stabilization, as well as the loop gain at the same frequency. Since more detailed analysis is required to evaluate the effects of such combustion modifications on the combustion time delay and the frequency-dependent loop gain function, this study examined the effects on the frequency-independent loop gain term represented by the resistance of the burners to air flow through the burners. This was done by considering only the air feed system response to boiler pressure perturbations. Coupling the combustion and combustor geometry response to complete the loop was left to more detailed studies. If air feed system coupling is responsible for the observed instabilities, then the instabilities should occur predominantly under operating conditions where the air feed system response is high.

3.2 CORRELATION OF OBSERVED INSTABILITIES WITH AIR FEED SYSTEM DYNAMIC RESPONSE

The air feed system response in its simplest linearized form is represented by the first diagram block of Figure 3-1. The term $2R\bar{\dot{w}}$ is the linearized form of the flow resistance in the square law flow relation:

$$\dot{w}^2 = \frac{\Delta P}{R} \tag{3-9}$$

This flow relation is often expressed as

$$\dot{w} = ADM \sqrt{\Delta P} \tag{3-10}$$

where ADM is the admittance to flow. The admittance form of the flow equation is usually used when flows are in parallel, as in a parallel multiple-burner array fed from a single windbox, because the total admittance of the array is the simple sum of the individual burner admittances. Similarly, the resistance form is used for the same reason when components are in series. Clearly, flow resistance is related to flow admittance by

$$R = \frac{1}{(ADM)^2} \tag{3-11}$$

Thus, the linearized air feed system response can be represented in terms of admittances by

$$\text{Flow response} = \frac{1}{2R\bar{\dot{w}}} = \frac{(ADM)^2}{2\bar{\dot{w}}} \tag{3-12}$$

This feed system response describes the perturbations in flow (in this case, air flow) from each individual burner. Assuming that the windbox volume is sufficiently large that small perturbations in flow through one burner do not affect local windbox pressures sufficiently to in turn affect adjacent burner flow (a reasonable assumption), then the response of each burner is independent of the others. Since the burner flow response concerns only the feed system and not the combustion or combustor response, it is independent of the type of combustor downstream of the feed system (e.g., rocket thrust chamber, turbojet combustor, or boiler).

The first observation from Eq. (3-12) is that if the mean air flow $\bar{\dot{w}}$ through a burner is reduced, the flow response is increased, and the likelihood of instability is increased. This is what occurs when NO_x ports are introduced into an existing boiler with no change in burner resistance. The NO_x ports introduce an additional air flow path, and less air is divided between the burners. One observation is that if the observed instabilities are of the air feed system coupled variety, then they should occur most frequently in older boilers that have been retrofitted with NO_x ports and more frequently when the NO_x ports are open rather than closed.

3.2.1 Air Flow Through Individual Burners

If the fuel that is being injected into the air stream in operating (F+A) burners or the initial flame anchored in or near the burner has no effect on the admittance to air flow through the burner, then the admittance of (F+A) burners would be the same as (Air) burners. The total air flow, therefore, would be equally divided between all burners whether they were (F+A) or (Air), and the BOOS technique for NO_x reduction would not have any effect on air feed system coupled stability. This assumption of equal air flow distribution between burners, not only between (F+A) and (Air) burners but despite windbox aerodynamic variations and nonuniform burner configurations, appears to be common in the industry and in boiler literature. Particularly with gas fuels and in the BOOS configuration, this assumption appears to be seriously in error.

Unfortunately, burner pressure drop instrumentation in most cases is inadequate. Small differences (13 to 25 gm/cm^2) (5 to 10 in. of water) between large numbers (over 1000 gm/cm^2)

(400 in. of water) must be measured. The measurement is usually made with single-point, standard, water manometers. At low boiler loads, the measured air pressure drop across a burner array may actually reach negative values although flow is still clearly in the positive direction. This measurement is not significant for any other operational or research purpose and, therefore, has not received great attention.

No measurements have been made of the air flow through (F+A) and (Air) burners in full-scale, operating, multiple-burner boilers. Not only are the combustion air temperatures high, greater than 530 degrees K (500 degrees F), but the flow into and through the burners is extremely complex. Some swirl is introduced in the air registers. At full load and with full open registers, however, the flames entering the boiler normally show little evidence of a positive swirl. Often the air register vanes are not at uniform angles to the circumference of the air register. In some cases, in the earlier data of this study, some of the register vanes may not have been open at all (tangent to the circumference), while others in the same register might have been hanging radially. These register problems have largely been corrected, but the data sample obtained may be clouded by such anomalies.

Flow measurements with a pitot-static rake or hot wire anemometers appear to be useless because of the flow complexity. Measurements might be made in an (F+A) burner by rake sampling the gases at the burner exit and measuring the fuel flow to the burner. This would be a complex and expensive task and has not been done to date.

With a large amount of data, reasonably accurate values of average windbox and furnace pressures and, therefore, average pressure drops across the entire burner array served by the windbox can be obtained. Reasonably accurate values of total air flow can also be established. From Eq. (3-10), average values of total burner array admittance (ADMT), plus NO_x ports where applicable, can be obtained for all configurations of (F+A) and (Air) burners and NO_x ports tested. It seems quite reasonable, considering the basic data accuracy and the averages taken, to assume (a) equal flow through all (F+A) burners, (b) equal flow through all (Air) burners, and (c) that the admittance to air flow through (Air) burners (ADMA) and the NO_x ports (ADMNP) are constant (i.e., independent of flow through the burners or NO_x ports). It does not appear reasonable to assume that the admittance to air flow through an (F+A) burner (ADMFA) is independent of burner operating conditions. Thus, for each operating configuration (for example, 16 burners (F+A), 8 burners (Air), and 2 NO_x ports open), an admittance equation can be written:

$$\text{ADMT} = 16\,(\text{ADMFA}) + 9\,(\text{ADMA}) + 2\,(\text{ADMNP}) \qquad (3\text{-}13)$$

where ADMT is averaged over a number of tests with these values of NFA, NA, and NNP, but not necessarily with the same burners (F+A) or (Air). If the ADMFA were independent of flow conditions in the (F+A) burner, only three such equations would be necessary to determine all of the admittances. Since this cannot be assumed, at least, with gas fuels, ADMFA is different for each test condition, and there is always one more unknown than available equations. Thus, an additional equation is needed.

There are two possible effects of the introduction of fuel in a burner on the air flow through the burner: (a) one is the axial momentum interchange between the air flow and the fuel flow in cases where there is appreciable mixing between the two fluids within the burner; (b) the other is the effect of heating of the A/F mixture by partially complete combustion within the burner. In the case of gas fuels, at least some of the gas is injected perpendicular to the air flow. A simple analysis indicated, however, even if all of the gas fuel were injected in this manner, with no axial velocity, the momentum exchange would have negligible effect on the admittance to air flow through the burner. In the case of oil fuels, the liquid spray is injected primarily in the direction of air flow and could act to aspirate the air flow, thereby increasing the admittance. The oil guns, however, are close to the exit of the burner. In this case, also, a similar analysis indicated a negligible effect on burner air flow admittance. The effect of a flame in the burner, however, can have a significant effect on the air flow admittance.

With gas fuels, it is necessary to provide a pilot flame in the burner to continuously ignite the fresh mixture and to control the point of flame initiation. Some of this pilot flame is provided in the low axial-velocity region in the center of the burner, due to the vortex-like flow resulting from the air swirl. In some cases, this pilot flame can be seen deep in the burner, even overheating the air registers. Some of the pilot flame could be provided in the flow recirculation zones just downstream of bluff bodies, such as the gas spuds or rings, or the oil gun and/or diffuser. It is clear that partial combustion of the air-gas fuel mixtures must and does occur within the burner.

With oil fuels, however, no pilot flame need be provided in the burner. The flame is instead stabilized around the liquid fuel droplets themselves, and the whole cloud of droplets can be continuously ignited by gross recirculation within the furnace. This kind of gross recirculation within the furnace could also provide air-gas fuel ignition except for the great danger of sudden flashback to the burner. Such flashback cannot occur with oil flames because the liquid fuel is not vaporized and mixed with the air close to the burner.

As mentioned, in operation the oil gun tip is near the exit of the burner and injects axially into the furnace. Thus, except for early fine atomization on the periphery of the spray and the possibility of some small reverse flow in the center of the burner due to the swirl, flames are unlikely to be back inside the burners with oil fuels, nor were they observed there.

Clearly, with almost any kind of pilot flame, the fraction of combustion completed near the flame holder, within the burner in this case, is some inverse function of the main stream velocity. If the velocity is increased sufficiently the flame can be blown completely out of the burner or liftoff of the burner. At a sufficiently slow velocity, all of the combustion could be completed within the burner. Therefore, at the highest velocities, the ADMFA for gas-firing burners should begin to approach the ADMA (no flame in the burner). Since flame liftoff represents a dangerous situation because of the possibility of flashback, however, such conditions are usually not allowed to exist. As a result, calculated values of ADMFA from gas-fired tests can approach but never be exactly equal to ADMA. At the higher burner velocities with oil fuels, however, the ADMFA should be very close to the proper values of ADMA. These observations provide the additional equation needed, with which all of the admittances for all burner and NO_x port configurations can be estimated. Analysis of the effect of heating of the A/F mixture within the burner on the air flow admittance (discussed later in this section) indicates that the presence of the flame in the burner will reduce this admittance. Therefore, the ADMA for all of the burners for each of the furnaces in this study were estimated according to the following procedure: (a) it was assumed that at high total air flow, using oil fuels, the measured ADMFA is equal to the proper value of the ADMA; (b) configurations were selected, where possible, where all burners were operating (F+A), a number of burners were completely shut off (no air or fuel), and the total air flow was large; and (c) tests were selected which yielded the highest calculated values of ADMFA.

The need to select only certain test conditions from which to calculate ADMA eliminated the advantage of averaging large amounts of data. Thus, the experimental errors in the small sample of data are more significant. No way to improve this method of estimating ADMA was found, and the derived values of ADMA remain estimates only. No pressure drop data were available for the smallest (Riley) furnace studied, and this furnace was subsequently eliminated from both the stability and the NO_x analyses. In the case of boilers S1/2, the desired oil-firing data were not available, and the value of ADMA was estimated by proportioning the ADMA for H1/2, with similar burners, according to burner flow area. Despite the obvious difficulties in estimating values of ADMFA and ADMA, the resulting air flow distribution is considered more correct than the common, but clearly erroneous, assumption of a uniform air flow distribution (equal values of ADMFA and ADMA) with gas fuels.

Figure 3-2 shows an example of ADMFA data calculated from cases where all burners were operating (F+A) but different numbers of burners were shut off completely (recognizing that there may be considerable but unknown air leakage through a fully closed register). In this case, only six test cases were available from gas-firings and eight from oil firings. Even to include this much data required that half of the cases used include open NO_x ports. It was necessary, therefore, to estimate an average value for ADMNP and correct both the ADMT and the air flow velocity through the burners for the NO_x port open cases. Since there were no (Air) burners in any of this data, ADMFA was simply the measured or corrected value of ADMT divided by the total number of operating burners.

The H3 boiler is of the face-fired horizontally opposed configuration with a partial divider wall and a total of 12 burners in 3 levels. Rated load is 240 MW. For the gas-fired data, all 12 burners were operating. For the oil-fired data, the number of operating

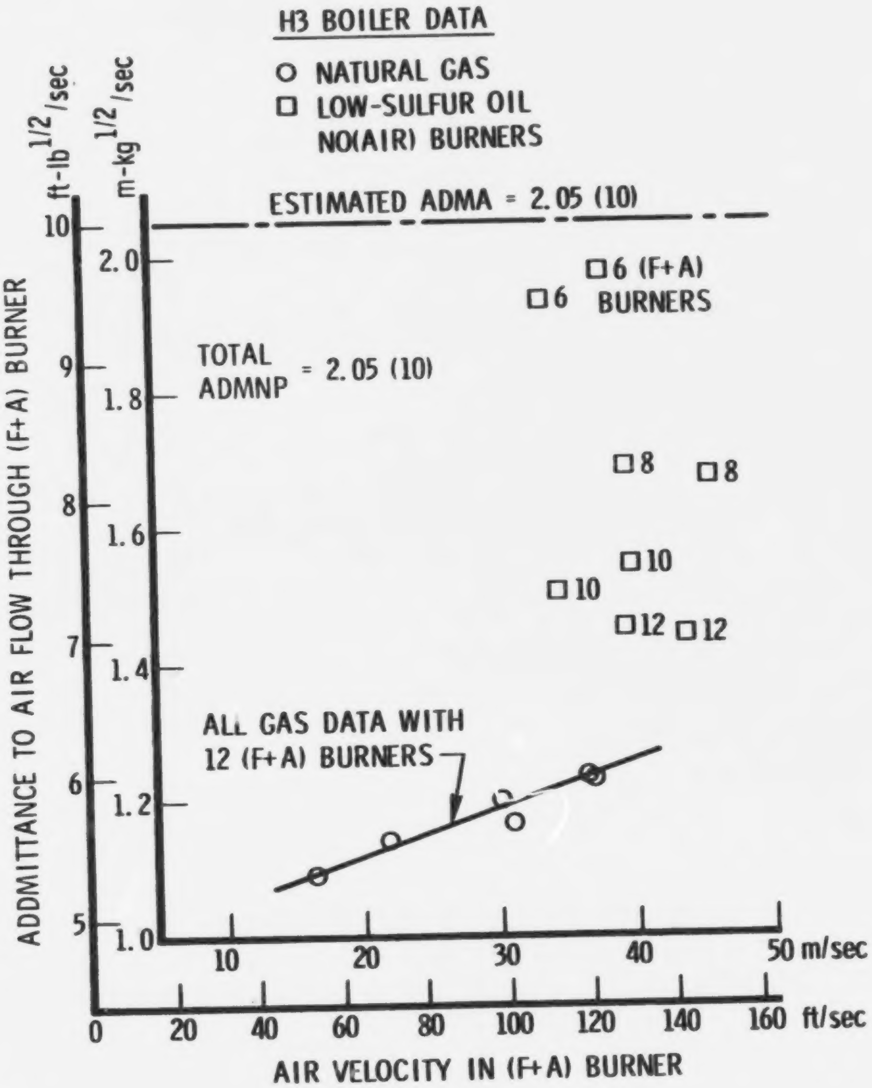


Figure 3-2. Effect of air velocity in an (F+A) burner on the admittance to air flow through the burner

burners varied from 12 to 6, as shown in Figure 3-2. The gas-fired data show a well-defined linear increase in ADMFA with air flow velocity through the burners. This is interpreted as a direct indication of the effect of the air velocity on the degree of combustion occurring in the burner. The absence of gas-fired data at velocities higher than about 37 m/sec (120 ft/sec) may be an indication that the flame will lift off the burner at these high velocities. The ADMFA would then rapidly rise to the ADMA value.

The oil-fired data, with the same number of burners operating as for the gas-fired data (12), show ADMFA values higher than those for the gas-fired case at the same burner velocities. The oil-fired ADMFA values, however, increase rapidly as the number of operating burners decrease. This may be due to the presence of a significant flame within the burners, even with oil fuels, or to significant air leakage through fully closed air registers. Just why an oil flame within a burner should be blown out of the burner more with fewer number of burners operating at the same flow velocity is not clear. It seems likely that an oil flame would not be well-anchored in the burner, because there is no need to anchor it there. As a result the initial flame position may "wander" significantly under the influence of minor flow configuration variations. An admittance value for a fully closed air register of as much as one-third that of a fully open register is necessary to explain the full variation of the ADMFA data for oil firings on the basis of air leakage alone. Introducing a fourth unknown admittance value to be determined from the data (for fully closed air registers) would further complicate an already nearly impossible task. Therefore, the commonly used assumption of zero admittance for a fully closed air register was maintained throughout this study. This effectively lumps any closed-register air leakage into that of the fully open (Air) burners (into ADMA). Since the ADMA should be higher than ADMFA with any possible flame present in the burner, ADMA was estimated slightly higher than the highest ADMFA calculated from the oil-fired data.

That ADMFA for the gas-fired cases is nearly a factor of two lower in admittance than the estimated value of ADMA is shown in Figure 3-2. This has significant implications to both stability and NO_x control. A remaining significant question concerns whether this value of ADMA could be even larger than estimated. Since the ADMFA values calculated from the oil data are increasing as the number of operating burners decrease and no limit is indicated by the data, it might be possible that ADMFA for less than six burners operating could be even greater than the estimated value for ADMA. The question concerns the value of ADMFA which represents the complete absence of oil flame in the burner (assuming no air leakage through closed registers). To answer this question, an analysis of the fraction of combustion (C_h) which must be completed within the burner to yield the calculated values of ADMFA for both gas and oil fuels was undertaken. This analysis is discussed in Appendix E.

The results of the C_h calculation for the data from gas- and oil-fired tests on boiler H3 are shown in Figure 3-3. The calculated values of C_h fall between the limits of zero (flame liftoff) and one (all combustion completed in the burners). A similar calculation was made to evaluate the effect of possible large air leakage through closed air registers. Again, the calculated values of C_h were between zero and one, although the maximum value was only about 0.5 for this case. Significant error in the estimated values of ADMA could easily yield values of C_h greater than one or less than zero. The highest values of ADMFA for the oil-fired data in Figure 3-2 indicate almost no combustion in the burner ($C_h \cong 0$), justifying the estimate of ADMA made earlier on the assumption that ADMFA for these oil tests were very nearly equal to ADMA. These conclusions, however, depend rather strongly on the single test which yielded a calculated value of C_h near

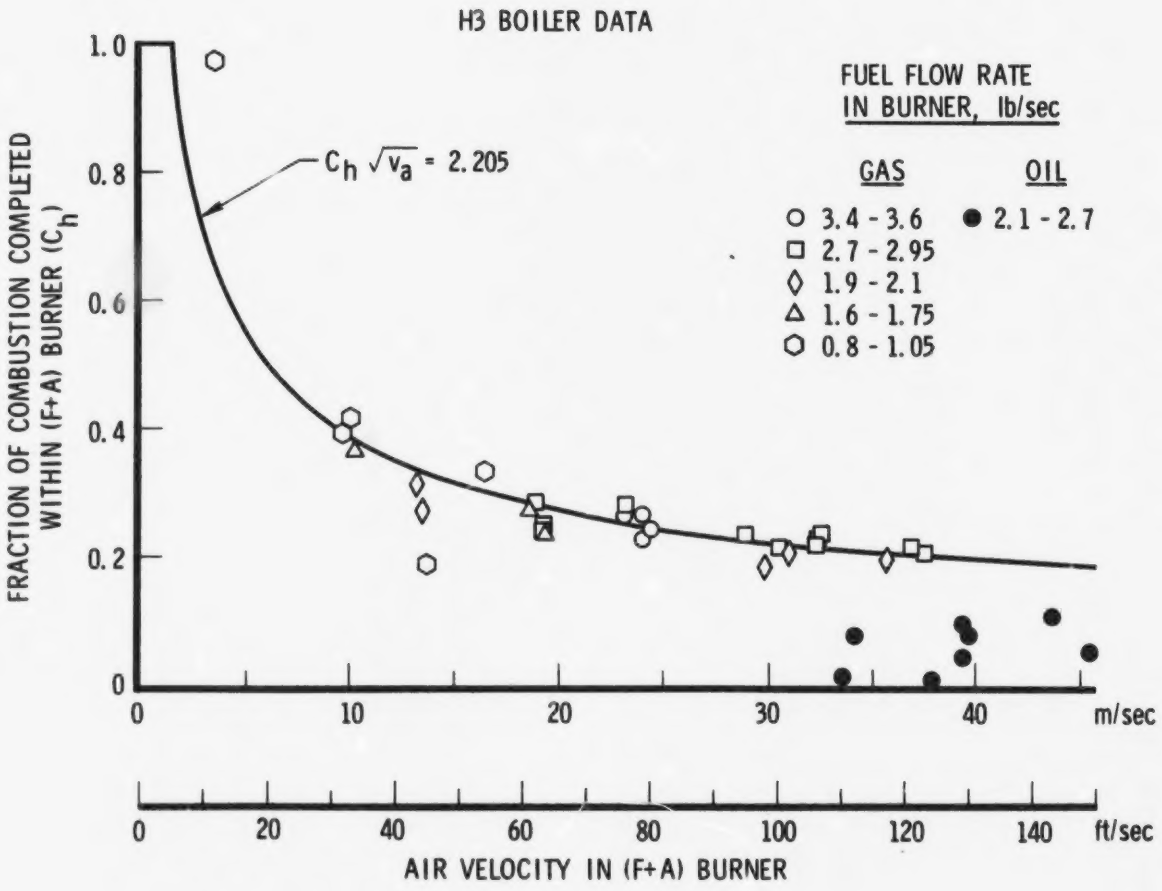


Figure 3-3. Effect of air velocity on the fraction of combustion completed within an (F+A) burner

1.0. The next largest calculated value of C_h is less than 0.5. It is unlikely that more data could be obtained which would yield high values of C_h because that is an undesirable operating condition, which would probably result in overheating of the air registers and perhaps damage to the burners. Lacking such further data, the results had to be accepted as they are, with reservations.

The data from gas firings could be empirically fit rather well with a function:

$$C_h\sqrt{v_a} = 2.205 \tag{3-14}$$

where velocity v_a is given in ft/sec. The range of fuel flows at any given air flow velocity indicates that the fuel flow rate has little effect on C_h and, therefore, that the air flow velocity is the major controlling parameter, as conjectured earlier. The magnitude, negative slope, and shape of the C_h versus flow velocity curve in Figure 3-3 have several significant implications with regard to both steady-state A/F ratios in (F+A) burners and the dynamic response of these burners to furnace pressure oscillations. They stem from the following observations:

a. The presence of partial combustion within a burner has a strong effect on the resistance to air flow through the burner. Thus, the steady-state A/F ratio in (F+A) burners can be significantly lower than would be calculated from an assumption of equal flow in (F+A) and (Air) burners.

b. The increased resistance to air flow in (F+A) burners tends to be a stabilizing influence on the air feed system response, but both the reduced air flow and the negative slope of C_h with velocity are destabilizing influences. When a small rise in furnace pressure causes a small reduction in air flow in an (F+A) burner, the air flow velocity through the burner will be reduced, the flame will retreat further into the burner, resistance will be increased, flow will be decreased further, until a stable point is reached. This nonlinear response will be stronger in configurations where the steady-state air flow through (F+A) burners is reduced and the slope of C_h versus flow velocity is more negative. The use of NO_x ports and BOOS techniques for NO_x control both create this reduced air flow.

c. Below some reduced air flow rate through (F+A) burners, and below some critical air flow velocity, the air flow can become what is called statically unstable. That is, the reduction in air flow due to the nonlinear effect can become self-accelerating, stopping only when the flame is fully back in the burner and C_h is equal to one.

The results of calculations of the steady-state A/F ratio in (F+A) burners are shown in Figure 3-4. Test data were obtained with as many as four (Air) burners in the array (NFA = 8). Under these conditions, the assumption of uniform air flow distribution to all burners indicates that the A/F ratio in (F+A) burners should be in the range of 10 to 11. Burner A/F ratios calculated from admittance data indicate that these ratios were actually in the range of 6 to 8. Note that the premixed flammable limit for a typical natural gas-air flame is about 9.7. Because the flame is actually a diffusion flame, local A/F ratios above this limit will exist in the burner, and a pilot flame can be sustained, but further flame propagation could be quenched as further mixing reduces the A/F ratio below the limit. Engineers' notes on the character of gas flames under such conditions tend to indicate lazy, sparking, diffuse, and opaque flames that appear ragged (detaching from the burners in chunks and quenching in the furnace) and not attached to ring burners around the full periphery. These indications are descriptive of lower than expected air flow rates and velocities, lower than expected A/F ratios, and A/F ratios below the premixed flammable limits. These indications are considered to support the conclusions of this study with regard to the effect of flames within the burners on air flow through the burners.

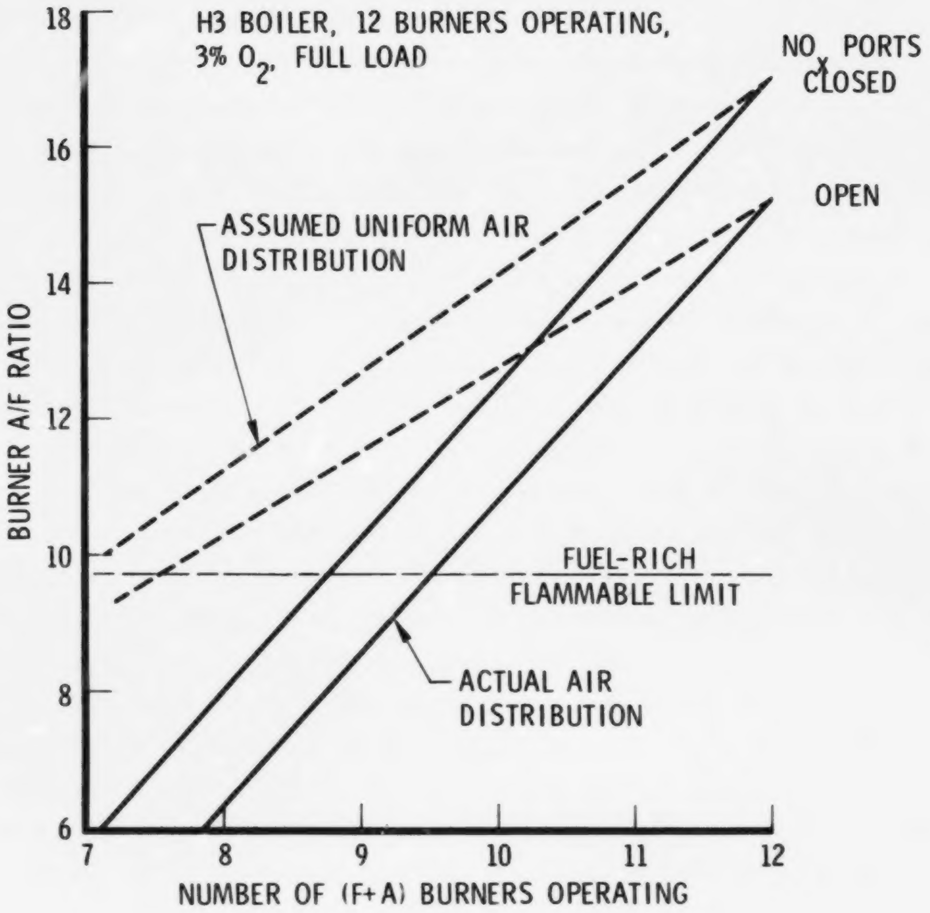


Figure 3-4. Effect of partial combustion in a burner on the A/F ratio in the burner with gas fuel

Again a check was made on the possible effects of large air leakage through closed air registers, in this case on the actual air distribution shown in Figure 3-4. The slope of the actual air distribution is somewhat shallower in this case, but still significantly steeper than that resulting from a uniform distribution assumption. The uniform distribution case, of course, would also include the assumption of zero leakage through closed air registers.

An attempt was made to include, also, the dynamic effect of the flame within the burner on the response of the air feed system to furnace pressure perturbations. This was approximated by including the slope of C_h with air flow velocity at each flow rate in the linearized resistance term, Eq. (3-12). Figure 3-5 shows the air feed system response calculated in this manner, again using H3/4 data, as a function of the fraction of the total number of operating burners [(F+A) plus (Air) burners] which are (F+A). The calculated response with all burners operating either as (F+A) or (Air), begins to rise rapidly when less than about two thirds (less than eight) of the burners are (F+A). In this case, Figure 3-4 shows that the steady-state A/F ratio in the (F+A) burners would be well below the premixed flammable limit. Attempts to reduce the fraction of operating burners further, which might have resulted in unstable operation, were frustrated by large increases in CO emissions, even with the NO_x ports closed. As a result, some of the burners were shut off completely. This increased the fraction of (F+A) burners and not only increased the A/F ratio in these burners and cleared up the CO problem but also increased the air flow velocity through the burners and strongly reduced the air feed system dynamic response.

3.2.2 Available Combustion Vibration Data

In general, a review of the available data from the standpoints of CO emissions and combustion instability problems verifies that (a) increases in CO emissions are generally related

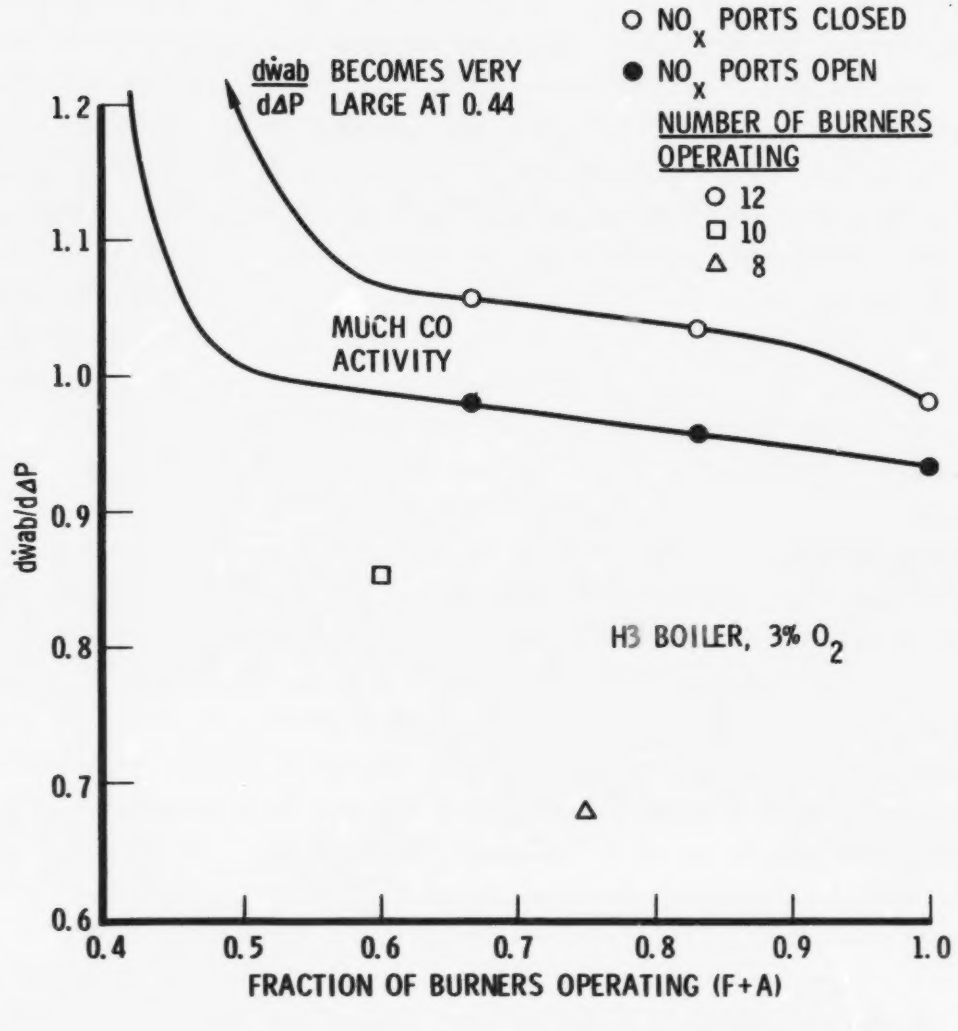


Figure 3-5. Response of air flow through an (F+A) burner to furnace pressure perturbations with gas fuel

to actual A/F ratios in (F+A) burners near or below the premixed flammable limit and (b) the CO emissions and combustion stability problems occur when about 75 percent or less of the operating burners are (F+A) and 25 percent are (Air) burners. Both of these conclusions are verified by data from a series of 12 tests conducted on boiler S1 for the purpose of evaluating combustion vibrations. These data are summarized in Figure 3-6. Although only four data points are shown, they represent repeated attempts to come back to, reproduce, and go beyond these configurations as well as all of the transition configurations between each condition shown. High vibration occurred with both configurations where 75 percent of the burners were (F+A) even though the total number of operating burners in the one case was half of that in the other case. Under those conditions creating large vibrations, the observed flames included all of the characteristics discussed, tending to indicate lower air flows in the (F+A) burners and A/F ratios near or below the premixed flammable limit. The high vibrations which occurred with only half of the burners operating occurred at part load where the air feed system response would again be high even though the full flow was diverted through only half of the burners.

Figure 3-6 also indicates that the observed vibrations are not likely to be due to typical induced draft fan instabilities. Fan instabilities tend to occur in operating regions where air volume flow is low and the fan discharge pressure is high. For any given number of burners operating (F+A), this unstable fan region should correspond to smaller numbers of burners operating (Air). That the observed trend toward vibration is opposite to this is shown in Figure 3-6.

One other observed case of high vibrations occurred in the largest boiler in the sample, H5. These tests involved the first firings with all new gas spuds installed. These spuds were designed to promote rapid mixing of the gas with the air within the burner. From the analyses and discussion to this point, it could be expected

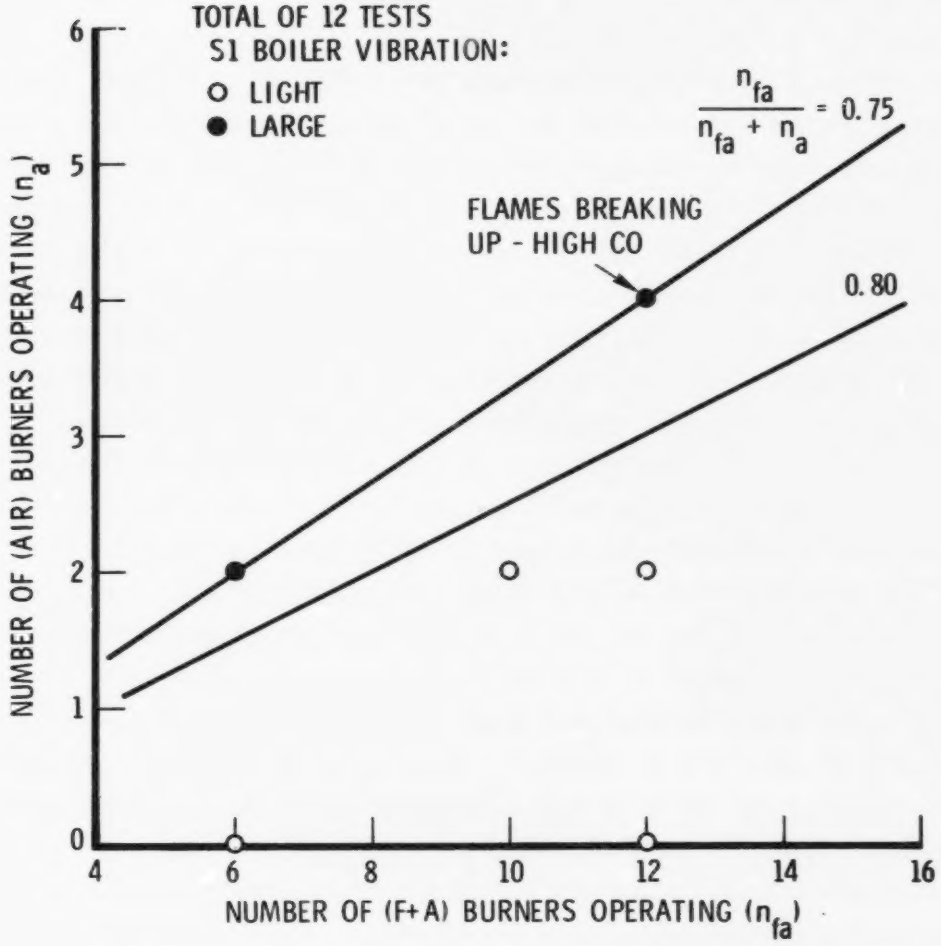


Figure 3-6. S1 boiler vibration test data with gas fuel

that the improved mixing would hold more of the flame within the burner, at any given air flow velocity, increase the (F+A) burner resistance to air flow, and reduce the (F+A) burner A/F ratio for any given burner configuration. All of this should have increased the probability of CO and combustion instability problems. As it turned out, the system was so severely unstable that these spuds and the design had to be discarded.

All of the instability occurred under part load conditions. The boiler could not be brought up to full load because of the violence of the instabilities. Neither could the operating conditions be held long enough to take data on windbox-furnace pressure drops or flue gas samples. All of the data was obtained from the environmental engineer's notes. To make the data useful at all, a subjective rating scale was used, rating the magnitude of the instabilities on a scale from 1 to 10 from comments in these notes. Clearly, such data are not accurate but do reveal some trends which are of value.

These rough average ratings are shown in Figure 3-7 on a plot similar to Figure 3-6. The same general trend appears as in Figure 3-6, in that the magnitude of the vibration increases markedly when 75 percent or less of the burners are (F+A). The point rated 10.0 was so severe that the steaming rate began to rise markedly and was almost out of control.

A microphone external to the boiler was used to tape record the vibration to allow frequency analysis. The most violent vibrations appeared to be in the ranges of 10 to 12.5 and 40 to 50 Hz. With the speed of sound of 900 m/sec (2950 fps), the lower frequency was found to correspond to a standing acoustic resonance (12.5 Hz) between the bottom and top of the furnace, a vertical distance of about 36 m (118 ft). This vertical height is unimpeded by any water tubes transverse to the flow. No apparent source of eddy-shedding exists in this volume. The higher frequency corresponds most closely to

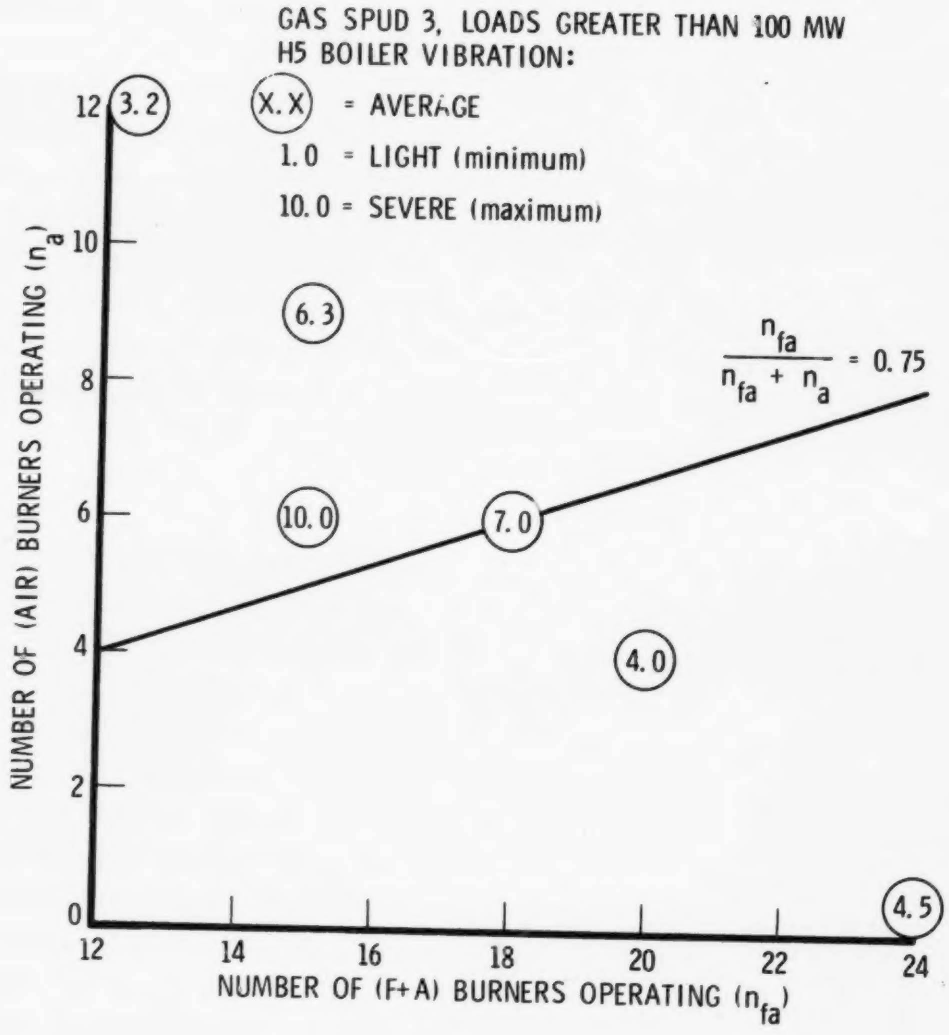


Figure 3-7. H5 boiler vibration data with gas fuel

the 9.14-m (30-ft) horizontal resonance (49.2 Hz) between the burner walls (firing faces in this opposed-fired boiler). The horizontal resonance is exactly what would be expected from coupling with burner feed system oscillations since all burners would be at a pressure antinode in that resonance. The vertical resonance is somewhat less likely since the burners are spread vertically, approximately from the pressure antinode at the bottom of the furnace nearly to the pressure node at the middle of the furnace. Some data involving this mode indicate that vertical location of the (F+A) burners had an effect on the instability.

Figure 3-7 also shows that at the extreme case of 50 percent of the burners (F+A) and 50 percent (Air) (NFA = NA = 12) that the vibrations appear to be minimum. It can only be conjectured, without further data or analysis, that this condition represents the case of flames fully back in the burners, where the nonlinear effect of flame position on air flow resistance is no longer a factor in the feed system response. This is the condition represented in Figure 3-3 by the constant value of C_h at 1.0. The more rapid mixing promoted by this gas spud makes such a case more probable.

An intriguing possibility of damping some of these modes with a Helmholtz resonator, analogous to the corner absorbers and acoustic liners of liquid rocket engines and afterburners of turbojet engines, is presented by the ash pit of this boiler. This pit, of the same horizontal dimensions as the furnace (9.14 × 10.1 m) (30 × 33 ft) and 0.914 m (3 ft) deep, is separated from the main furnace volume by a neck running the full width of the furnace (10.1 m) (33 ft) and approximately 0.76 m (2.5 ft) in the front-to-back direction. The FGR flow is introduced into the furnace through this pit and neck. This general configuration is that of a classical Helmholtz resonator. The current dimensions yield a resonant frequency of about 27 Hz. By appropriate modification of the pit volume and neck geometry and by the addition of two partitions, this volume could be converted to two resonators near the side walls tuned to the 40 Hz of the furnace width resonance and a single central resonator tuned to the 12.5 Hz of the vertical resonance. The neck is in the wrong location (at a pressure node) for effective damping of the horizontal furnace depth resonance. Although there does not appear to be any need for the gas spud design associated with the high vibrations observed in this furnace, such an application of damping devices to stabilize a large boiler has never been attempted. The inadvertent presence of this resonant damping device could explain the absence of vibrations in the frequency range around 27 Hz.

3.3 COMBUSTION STABILITY CONCLUSIONS

It appears that the available data on combustion instability and flame stability problems can all be explained by air feed system problems. Both appear to result largely from the nonlinear effect of the presence of the flame within the burners on the resistance to air flow through the (F+A) burners. In general, this resistance appears to be strongly controlled by the heat addition of partial combustion within the burner. As long as all combustion air flow paths are equal [no NO_x ports, no (Air) burners], the air flow distribution to all (F+A) burners will be the same. Any changes in air flow resistance will simply result in changes in the overall windbox-furnace pressure drop required to maintain the same flow. The resistances to air flow through NO_x ports and (Air) burners, however, are less than that of the (F+A) burners and appear to be independent of air flow rates. In cases where NO_x ports are introduced (two-stage combustion) or fuel is shut off to some of the burners (BOOS) for purposes of reducing NO_x, not only is the proportion of the combustion air flowing through the remaining (F+A) burners substantially decreased, but the resistance to air flow through (F+A) burners becomes a nonlinear function of the flow itself.

A reduction in air flow through an (F+A) burner allows more of the combustion to be completed within the burner. This increases the resistance to air flow through these burners and diverts a larger proportion of the air flow to the NO_x ports and the (Air) burners. This diversion of air flow away from the (F+A) burners allows even more complete combustion within the burners, further increasing resistance, diverting more flow to the nonburning paths and compounding the effect. When a certain fraction of the air flow is being diverted to nonburning paths, this nonlinear effect causes problems in both the combustion and flame stability areas.

The air feed system response is high with any burner configuration because of the low windbox-to-furnace pressure drop. In fact, this low pressure drop allows the flame in the burner to dominate the air flow resistance. As more air flow is diverted away from the (F+A) burners, the air feed system response becomes larger and, at some critical fraction, air feed system coupled modes can become unstable. The data appear to indicate, at least with the hardware studied, that this critical fraction occurs when less than 75 percent of the operating burners are (F+A).

This same nonlinear effect causes the A/F ratio in the (F+A) burners to decrease to much lower values than would be calculated under the assumption of uniform distribution of air flow between all burners, both (F+A) and (Air). As the air flow through and the A/F ratio in the (F+A) burners decreases, the flame advances further into the burner, and register overheating problems can result. Again, when about 75 percent or less of the burners are (F+A), the A/F ratio appears to decrease below the rich premixed flammable limit for natural gas fuels. Ragged flames, difficulty in flame-holding, and pulsating flames can occur. On the other extreme, gas spuds designed empirically for less rapid gas-air mixing to promote stable operation under two-stage combustion or BOOS conditions may not adequately anchor gas flames at high flows, and flame liftoff problems can occur.

It is not as important to anchor oil flames in the burners as it is gas flames. As a result, little burning is apparent within the burners with oil fuels, and none of the nonlinear effects related to gas flames are apparent. Combustion instability, register overheating, and flame liftoff problems are not apparent in oil-fired data. Future oil-firing configurations designed for minimum NO_x, however, may require much finer oil atomization and may introduce all of the gas-fired combustion and flame stability problems discussed herein.

Thus, the general mechanism of combustion and flame stability problems observed in the data appears to have been identified and verified. Although the analytical techniques are available, this mechanism was not modeled or examined further. Complete analysis, including design recommendations for avoiding these problems, has been deferred to later studies.

NOMENCLATURE

ADMA, ADMFA, ADMNP, ADMT = admittances to air flow through an air-only (Air) burner, a fuel plus air (F+A) burner, a NO_x port, and the total of all of these, respectively, $m\text{-}kg^{1/2}/sec$ ($ft\text{-}lb^{1/2}/sec$)

A_t = area of the choked throat of a rocket motor nozzle, m^2 (ft^2)

C_h = fraction of fuel reacted within the burner

C^* = characteristic velocity of the combustion products in the throat of a rocket motor nozzle, m/sec (ft/sec)

K = ratio of densities of the combustion products to the reactant being injected

M = molecular weight

NA = number of air-only (Air) burners

NFA = number of fuel-and-air (F+A) burners

NNP = number of NO_x ports open (flowing combustion air)

P = pressure, kg/m^2(abs) (lb/ft^2)

ΔP = pressure drop across an injector orifice or a burner, kg/m^2 (lb/ft^2)

R = flow resistance, $sec^2/kg\text{-}m^2$ ($sec^2/lb\text{-}ft^2$), defined by Eq. (3-9)

R_0 = universal gas constant

s = the Laplace operator

T = temperature, degrees K (degrees F)

V_c = volume of the rocket motor combustor (to the choked throat), m^3 (ft^3)

v = velocity, m/sec (ft/sec)

$\dot{w}$ = weight flow rate, kg/sec (lb/sec)

ρ = mass density, kg-sec^2/m^4 (lb-sec^2/ft^4)

τ = combustion time delay, sec

Subscripts

a = air

b = burner

c = combustor

d = delayed flow (in time)

f = fuel

m = manifold (or windbox)

p = reaction products

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APPENDIX A

DEVELOPMENT OF THE CORRELATING EQUATION

A. 1 INTRODUCTION

The approach taken in this study in an attempt to elucidate the effects of hardware and operating condition variations on the NO_x emissions from large multiple-burner utility boilers was (a) set up a crude model of the NO_x generation process in these boilers, (b) develop an equation from that model consisting of the sum of a number of linear terms which if all processes were accurately described would predict the NO_x emissions, (c) use that equation to correlate a large amount of NO_x emissions data from such boilers, and finally (4) gain understanding of some of the poorly known processes and the overall effects of these modifications on NO_x emissions by exercising and evaluating the resulting correlation equations. Major assumptions involved in the development of the correlation equation are discussed in the text of this report, while some of the details of this development are described in this Appendix.

Development of the correlation equation was initiated by defining the simple mixing zones shown in Section 2,Figures 2-1 and 2-2. Further definitions of relative burner combinations and of the assumed recirculation flow are shown in Figure 2-3. A brief description of the mixing zones follows.

A.2 PRIMARY MIXING ZONE

The primary mixing zone is the core flow zone where the flow from an individual burner issues into the furnace. It is taken to be two burner diameters in length. The A/F ratio is that of the burner alone. Stay time in the zone is calculated from the constant zone length divided by the burner flow velocity. Cooling time is taken as one half of the stay time.

A.3 RECIRCULATION MIXING ZONE

The recirculation zone represents a complex flow and mixing region. Clearly, entrainment by the flow from a burner causes some kind of flow toward the burner but where it comes from, where it goes after some entrainment, and what its prior mixing and cooling history has been in all cases is not clear. Since it represents a flow path in parallel to the main flow of gases from a burner through the furnace, it complicates an attempt to sum the series contributions of each mixing zone through which the flow passes. It seems clear that there should be a general upward flow of these gases along the wall. For purposes of this approximate model, then, the following simplifying assumptions were made:

a. The recirculation flow travels in a circle of mean diameter equal to the length of the primary zone (Section 2, Figures 2-1 and 2-2) at the velocity of the primary zone. As a result, the stay time in the zone is π times that of the primary zone.

b. For the sake of simplicity, the total amount of flow recirculating is taken as 32 percent ($1/\pi$) of the primary zone flow.

c. Since the amount of NO_x generated in a given zone depends on the product of the amount of flow involved and the stay time, the later two assumptions make the product for the recirculation region equal to the product for the primary zone flow.

d. Since the recirculation flow is assumed to leave the main flow at one level and reenter the main flow in the level above (Section 2, Figure 2-3), the recirculation flow at any one level is treated as in series with and between the primary and secondary flows at that level.

e. The recirculation flow entering and mixing with primary zone flow at a given level is taken at the A/F ratio of the burner below.

f. The flow departing the main flow at a given level to recirculate (the flow treated as in series with the primary and secondary flows at that level) is taken at the A/F ratio resulting from mixing of 68 percent of the primary flow at that level and 32 percent of the primary flow from the burner below.

A.4 SECONDARY MIXING ZONE

The secondary mixing zone is considered physically to be that zone where the primary and recirculation flow mixing is taking place. The uniform A/F ratio in the zone is taken to be the same as that in the recirculation region. The length of the zone at the lowest level is taken to be one third of the distance from the end of the primary zone to the furnace centerline (opposed firing) or to the backwall (single wall firing). This length is reduced by the bulk gas flow, linearly, to zero from the fourth to the sixth level. The flow is assumed to fill one half of the furnace width, and therfore the average velocity in the zone is that of the primary zone reduced by one half of the ratio of the burner-to-furnace horizontal width. Cooling time to the zone is the sum of the stay times in the primary and recirculation regions plus one half of the stay time in the secondary zone.

A.5 ADJACENT AND OPPOSITE MIXING ZONES

In the adjacent and opposite mixing zones, one half of the secondary zone flow from a given burner is taken to mix with that from the horizontally adjacent burner and the other half with that from the horizontally opposed burner (if opposed firing). Adjacent mixing is prohibited where a divider wall may exist. The lengths of both adjacent and opposite zones at the lowest level are taken as two thirds of the distance from the end of the primary zone to the furnace centerline (opposed firing) or the back wall (single wall firing). The length of these zones is linearly reduced to zero, by the bulk gases, from the first to the third level. The flow velocities in these regions are taken to be the same as that of the average in the secondary mixing zones. Therefore, the stay times in the adjacent and opposite mixing zones is twice that of the secondary zones. Cooling time to the adjacent and opposite mixing zones is the sum of the stay times in the primary, recirculation, and secondary zones plus one half of that in the adjacent and opposite zones.

A.6 BULK GAS MIXING ZONES

The gases entering the bulk gas mixing zones at each level are the sum of those from the burners at that level plus the bulk gases from below. All of the recirculated flue gas is assumed to enter the bulk gases, only, at the first level. Since the NO_x introduced into the boiler with the FGR is again removed from the flue gases at the boiler exit, forming a steady closed loop, flue gases are treated throughout as inert gases containing no NO_x. From the standpoint of NO_x concentrations, the main fuel and air reaction products are treated as undiluted by the (parallel) stream of recirculated flue gases. The FGR in this model, however, does affect the bulk gas temperature and velocity. The length of each bulk gas mixing zone is taken as the distance between burner centerlines (levels). The bulk gas velocity is calculated from the total fuel, air, and FGR flow and the overall furnace cross-sectional area. This velocity is assumed constant at all levels of the furnace, with the bulk gas flow area assumed to spread (Section 2, Figure 2-2) in proportion to the bulk gas flow until all flows are in the furnace and the bulk gases fill the total cross-sectional area.

Cooling times for the flow coming from the burners are the sum of all of the intermediate mixing zone stay times. Cooling times for the bulk gases are the stay times for one bulk gas mixing zone. The gases from both sources are first mixed to determine an average temperature at the beginning of the bulk gas zone and are then allowed to cool for one half of the bulk gas zone stay time, when a mean uniform temperature for that zone is calculated.

A.7 NO_x PORT MIXING ZONE

At the end of the primary furnace zone (not the burner primary mixing zone), the bulk gases are at some calculated temperature and of some composition. If there are NO_x ports in the furnace which are open, the composition of the bulk gases will be that resulting from substoichiometric A/F combustion in the furnace primary region. As the air flow from the NO_x ports is mixed into this bulk gas flow the A/F ratio of the bulk gases will pass through stoichiometric, ending at the final overall furnace A/F ratio, which always contains excess (above stoichiometric) air. The rate of this mixing is not known. In this model, the mixing rate is assumed to be rapid and, therefore, the air-fuel ratio in the NO_x port mixing zone is always taken at the overall furnace air-fuel ratio, regardless of the presence of NO_x port flow. In the four furnaces studied which have NO_x ports, the length of this zone was arbitrarily set at 10 ft. The velocity through the zone is again taken to be the constant furnace velocity.

A.8 FINAL MIXING ZONE

In all probability, by the time any NO_x port flow is mixed into the bulk gases, a large amount of heat will have been rejected to the water walls, and the gas temperature should be low enough that NO_x formation rates are negligible. A final zone was established, however, reaching from the top of the NO_x port mixing zone to the first major convective cooling tubes (end of the radiant sectio of the boiler). The air-fuel ratio is that of the overall furnace. The velocity (for stay time) is that of the bulk gases. The mean temperature is taken as that calculated at the end of the NO_x port mixing zone (or top level of bulk gases if no NO_x port flow is involved), further cooled by the constant cooling rate for one half of the final-zone stay time.

A.9 SIMPLIFICATION

Much of the complicated reasoning, assumptions, and simplifications are to establish what important furnace geometry, burner array, and operating condition variables can be significant to the overall generation of NO_x. The detailed calculations of NO_x generated in each and every possible mixing zone are relatively unimportant. Of primary importance is the fact that the sum of the NO_x contributions of these individual mixing zones provides at least one rational means of explaining or accounting for the effects on overall NO_x generation of such primary variables as: (a) the overall boiler air-fuel ratio, (b) NO_x ports, (c) BOOS, (d) combustion air and fuel temperatures, (e) any combination of adjacent burners (vertically, horizontally, and opposite), (f) furnace cooling factors, (g) furnace geometry, and (h) the FGR.

The sum of these 104 mixing zones having been found, as a function of these multiple independent parameters, the sum can now be simplified for easier handling as a correlation equation. Much of the error and gross simplification will be corrected in the data correlation. The remaining errors will determine the goodness of the fit.

A separate A/F ratio must be used for each of the bulk gas mixing zones, the NO_x port, and the final mixing zones. For the remaining 96 burner mixing zones, however, only 4 separate A/F calculations are necessary. These result from certain (F+A) and (Air) burner combinations. No A/F calculations are necessary for (Air) burners alone or for mixing between (Air) burners since no NO_x can be generated in these pure air zones.

From the standpoint of cooling times (mean times to a given zone) and stay times in a zone, the bulk gas, NO_x port, and final mixing zones require separate calculations. Only 6 separate calculations of cooling and stay times are necessary for the 96 burner mixing zones. These result from the four main mixing zones, defined at the lowest level and the secondary and adjacent opposite zones shortened by the bulk gases at the fifth and second levels, respectively.

The possible combinations of the 4 A/F and the 6 time calculations result in 14 separate terms to describe the NO_x contributions of the 96 burner mixing zones. Together with 6 terms to describe the 6 bulk gas mixing zones and 1 each for the NO_x port and final mixing zones, a total of 22 terms to describe the NO_x contritions from all of the 104 possible separate mixing zones. These 22 terms are designated by a code as follows:

$$\Delta NO_x = C(NABXX)\ (DABXX)$$

where

N = the numbers of zones of the type ABXX

D = the NO_x contribution from all zones of the type ABXX

A = the type of adjacent burner combinations yielding a given type of A/F in the zone (for convenience, six numbers are used although they represent only four A/F)

where

1 = primary (F+A) burner

2 = an (F+A) burner vertically above an (F+A) burner or a zero flow burner (same A/F as 1).

3 = an (F+A) burner horizontally adjacent to or opposite an (F+A) burner or a zero flow burner (same A/F as 1).

4 = an (F+A) burner vertically above an (Air) burner

5 = an (Air) burner vertically above an (F+A) burner

6 = an (F+A) burner horizontally adjacent to or opposite on (Air) burner

B = the type of mixing zone

where

P = primary

R = recirculation

S = secondary

O = horizontally adjacent or opposite

XX = numbers describing the appropriate burner levels where the zones are similar. Where only one level is described the code is 0X.

For example, the term describing the NO_x contributions from all recirculation mixing zones where an (F+A) burner is directly above an (Air) burner would be

$$\Delta NO_x = C_7 \text{ (N4R16) (D4R16)} \qquad \text{(A-2)}$$

The six bulk gas mixing zone contributions are arbitraily designated by the code DNFX, where X = 1 to 6. The NO_x port and finaly mixing zone contributions are simply DNST and DNT, respectively. The 22 parameters used to describe the total thermal NO_x generated in the entire boiler are listed below:

1. (N1P16) (D1P16)
2. (N2R16) (D2R16)
3. (N2S14) (D2S14)
4. (N2S05) (D2S05)
5. (N3O01) (D3O01)
6. (N3O02) (D3O02)
7. (N4R16) (D4R16)
8. (N2S14) (D4S14)

9. (N4S05) (D4S05)
10. (N5R16) (D5R16)
11. (N5S14) (D5S14)
12. (N5S05) (D5S05)
13. (N6O01) (D6O01)
14. (N6O02) (D6O02)
15. DNF1
16. DNF2
17. DNF3
18. DNF4
19. DNF5
20. DNF6
21. DNST
22. DNT

Each of the 22 terms in the correlation equation, describing the mixing zones, involves one of these parameters and an unknown coefficient to be determined by the linear regression analysis of data. For correlation purposes, a simple constant term is also included in the sum. Finally, a term is rather arbitrarily included in the sum to account for the NO_x contribution from the bound nitrogen in oil fuels. This bound-nitrogen term will be discussed later.

The initial correlation equation used consisted of 24 terms, 22 for thermal nitrogen conversion, and one constant. These were considered adequate to correlate any case of wall-fired boilers with gas or oil fuels and with or without staged combustion or BOOS. Correlations involving furnaces with less than 24 total burners or burner arrays of different width or height were handled by deleting or expanding some of these terms.

A. 10 CALCULATION PROCEDURE FOR THERMAL NO_x

Calculation of the ΔNO_x terms of the type shown in Eq. (A-1) thermal fixation involves the number of times a given combination of (F+A) and (Air) burners occurs in burner array (NABXX) and the increment of NO_x formed in zones of that type. The calculation of NABXX terms is straightforward, involving only the summing those combinations. All of the complexity is in the DABXX terms.

The total ΔNO_x produced in the furnace is the sum of all of the NO_x increments in each zone that a given burner flow passes through. Because of the way that the burner mixing zones were set up, the flow from each burner passes, in series, through primary, recirculation, secondary and combined adjacent-opposite mixing zones. The ΔNO_x generated in each of these zones is represented by the first 14 terms of the correlation equation. Each of these terms is the product of (a) the average total weight flow from a single burner, (b) the stay time in the zone, and (c) the mean rate of change of NO_x concentration within each zone. But the stay time in a given zone is calculated from the length of the zone divided by the average flow velocity in the zone. Therefore, the stay time is inversely proportional to the total weight flow from a burner, and the product of (a) and (b) is independent of the flow rate through the zone.

The vertical flow velocities in the bulk gas, the NO_x port, and the final mixing zones were assumed to be equal. This velocity is inversely proportional to the total furnace throughput. The product of the total flow through these zones and the stay times in the zones, therefore, are independent of total flow.

This does not imply that the total NO_x emitted from the furnace is independent of the furnace load. At reduced load or throughput flow, the cooling times become longer, and the mean temperature in a given zone and the combustion air temperature will be lower. Since the effect of cooling times appears in the argument of the exponential in Section 2, Eq. (2-1), the rate of NO_x formation will be reduced. Total NO_x generated, then, will decrease with decreasing load, as was consistently observed in many boilers.

In the calculation of the DABXX terms, however, this constant product is a convenient simplification in that the product of flow rate and stay time can be combined into a pseudo-stay time, which is almost strictly a function of geometry alone. Since most of the NO_x is generated in the burner mixing zones and burner geometry is not greatly different between the boilers to be correlated, this constant product should not be greatly different between boilers. For purposes of correlation, this relatively constant product term is multiplied by a coefficient which is determined by the data correlation. For simplicity, the product of flow rate and stay time is incorporated into the correlation coefficient and is not calculated as such. The parameter DABXX in Eq. (A-1),therefore, is simply the rate of change of the NO_x mole fraction, as shown in Section 2, Eq. (2-1). It must be kept in mind, however, that the correlation coefficients [C in Eq. (A-1)] of each term have the dimensions of a weight flow rate times a time.

Estimation of the stay times themselves cannot be eliminated entirely because the appropriate sums of stay times represent the mean cooling times to the zones. The stay times are all calculated from the mixing zone lengths and the flow velocities. From the general descriptions of the mixing zones, the burner mixing zone lengths (in Fortran notation) were determined as follows:

For the primary and recirculation zones:

ZLP = 2.* HWB (A-3)

For the adjacent-opposite zones in opposed-firing boilers:

ZLA0 = [(HDF/2.) - ZLP]/1.5 (A-4)

For single wall-firing boilers:

ZLA0 = (HDF - ZLP)/1.5 (A-5)

For the secondary zones:

ZLS = ZLA0/2. (A-6)

The lengths for the bulk gas, NO_x port, and final mixing zones are defined as HBB, ZLNP, and ZLF, respectively.

Again from the assumptions concerning the mixing zones, the velocities in the zones are as follows:

For the primary and recirculation zones:

$$VP = WB/(RH0 * AB) \tag{A-7}$$

For the secondary and adjacent/opposite zones:

$$VSA0 = 2. * WB/(RH0 * HWF * HWB) \tag{A-8}$$

For vertical furnace velocities:

$$VF = WPT/(RH0 * HWF * HDF) \tag{A-9}$$

Equations (A-8 and (A-9) can be written in terms of the primary zone velocity:

$$VSA0 = VP * \pi * HWB/(2. * HWF) \tag{A-10}$$

and

$$VF = VP * WPT * AB/(WB * HWF * HDF) \tag{A-11}$$

By use of (A-7), (A-10), and (A-11) and the appropriate mixing zone lengths, all of the zone stay times can be calculated in terms of the primary zone stay time. The primary zone stay time is calculated from

$$\mathrm{TUP} = .01369 * \mathrm{ZLP} * \mathrm{AB}/\mathrm{WB} \tag{A-12}$$

The remaining mixing zone stay times are:

$$\mathrm{TUR} = \mathrm{TUP} \tag{A-13}$$

$$\mathrm{TUS} = \mathrm{TUP} * \mathrm{K21}/2 \tag{A-14}$$

$$\mathrm{TU0} = \mathrm{TUP} * \mathrm{K21} \tag{A-15}$$

$$\mathrm{TUF} = \mathrm{TUP} * \mathrm{KF0} \tag{A-16}$$

where

$$\mathrm{K21} = (2. * \mathrm{HWF} * \mathrm{ZLA0})/(\pi * \mathrm{HWB} * \mathrm{ZLP}) \tag{A-17}$$

and

$$\mathrm{KF0} = (\mathrm{WB} * \mathrm{HWF} * \mathrm{HDF} * \mathrm{HBB})/(\mathrm{WPT} * \mathrm{AB} * \mathrm{ZLP}) \tag{A-18}$$

Finally, the mean cooling time to a given zone can be calculated by summing the stay times in the preceding zones and one half of the stay time in the given zone. For proper coordination of cooling times with the corresponding values of NABXX and DABXX, a similar code was assigned such that cooling times to the burner mixing zones are designated by TUBXX terms, where TU designates a cooling time and B and XX have the same meaning as in NABXX and DABXX. Bulk gas cooling times are designated by TUFX terms. Recalling that the secondary zones are shorter at level 5 and the adjacent-opposite zones shorter at level 2, the calculations for cooling times to the burner and bulk gas mixing zones are as follows:

$$TUP16 = .5 * TUP \tag{A-19}$$

$$TUR16 = 1.5 * TUP \tag{A-20}$$

$$TUS14 = (1. + .25 * K21) * TUP \tag{A-21}$$

$$TUS05 = (1. + .125 * K21) * TUP \tag{A-22}$$

$$TU001 = (1. + K21) * TUP \tag{A-23}$$

$$TU002 = (1. + .75 * K21) * TUP \tag{A-24}$$

$$TUF(1) = (1. + 1.5 * K21) * TUP \tag{A-25}$$

$$TUF\ (2) = (1. + 1.25 * K21 + 0.5 * KF0) * TUP \tag{A-26}$$

For boilers H5/6, the burners are separted between burner levels 3 and 4 by more than the separation between other levels (because of the vertical grouping of burners into cells of three burners each). Other LADWP boilers maintain equal spacing and have no more than four levels. Therefore, for the H5/6 boilers, it was found:

$$TUF(3) = (1. + K21 + 2. * KF0) * TUP \tag{A-27}$$

$$TUF(4) = (1. + .875 * K21 + 3. * KF0) * TUP \tag{A-28}$$

$$TUF(5) = (1. + .75 * K21 + 3.2 * KF0) * TUP \tag{A-29}$$

$$TUF(6) = (1. + .625 * K21 + 4.285 * KF0) * TUP \tag{A-30}$$

and for all other LADWP furnaces:

$$TUF(3) = (1. + K21 + KF0) * TUP \qquad (A\text{-}31)$$

$$TUF(4) = (1. + .875 * K21 + 1.5 * KF0) * TUP \qquad (A\text{-}32)$$

The combustion product temperature in each of the combined zones where the A/F ratio in the zone and the cooling time to the zone are the same is then calculated from the sum of the initial reactant temperature, the temperature increase due to reaction at the A/F ratio in the zone (shifting equilibrium) and the temperature decrease due to cooling enroute to the zone. The initial reactant temperature was calculated as that resulting from mixing of the air flow through the operating (F+A) burners at temperatures measured at the outlet of the air preheater and the fuel at ambient temperature (300 degrees K) (80 degrees F). No data were available to estimate combustion air temperature changes between the air heater outlet and the individual burners. The temperature increase due to reaction was calculated using an Aerospace equilibrium combustion program and read into the correlation program in tabular form as a function of A/F ratio alone. The calculation was performed under constant conditions of 1-atm pressure and 533 degrees K (500 degrees F) reactant temperatures. This same calculation yielded the equilibrium concentrations of molecular nitrogen and oxygen, and the product of $[N_2][O_2]^{1/2}$ was also entered in the correlation program in tabular form. Cooling enroute to the zones under the constant cooling rate assumption discussed in Section 2 was calculated simply from the product of that constant cooling rate and the cooling times shown above in Eqs. (A-19) through (A-32).

The complete correlation equation, consisting of the sum of 24 linear terms, was used in some preliminary correlations to establish those terms and combinations of terms that were significant to the correlation, yielded acceptable correlation coefficients, and gave the most meaningful results.

None of the terms involved in this correlation equation are independent of the others. Rather, the independent variables are buried in each of the terms in complex nonlinear fashion. Thus, it was expected that the resulting correlation equation would not consist of terms describing directly the individual contributions of NO_x from each zone described and that terms would be negative as well as positive. The correlation program evaluated the significance of each of the terms to the correlation by determining whether the term was important in obtaining a good fit of the data. It quickly became clear that the final zone, downstream of the NO_x port mixing zone, was insignificant to the correlation, as were some of the bulk gas mixing zones and, of course, the bound-nitrogen term in the case of natural gas fuel. Only the final zone term was deleted on this basis. The bulk gas terms were instead combined into one term consisting of the sum of the six bulk gas zone terms DNF1 through DNF6. These terms were still calculated individually but were summed into one term in the correlation equation. After the initial confirmation, the nitrogen in the natural gas fuel was considered not as bound nitrogen, and that term was set to zero in all further correlations of natural gas-fired data.

Further correlations using an equation consisting of the remaining 18 terms indicated that good correlations could be obtained, but some very large coefficients resulted for some of the terms. Exercising the resulting equation with input conditions not close to the data actually correlated resulted in the calculation of NO_x emissions that were far from reality. This appeared to result primarily from allowing too many degrees of freedom in the correlation and from the fact that the terms in the correlation equation were not independent. Combining certain closely related terms not only reduced the degrees of freedom for correlation but increased the degree of independence of the remaining terms. Consequently, the correlation coefficient was reduced somewhat, but the resulting equation was quite stable. As always with empirical data correlations, however, care must still be taken in interpreting the results of interpolations and extrapolations that are far removed form existing data. Large data samples including wide ranges of the independent variables are necessary to improve confidence in interpolations and extrapolations. Further discussion on simplification of the correlation equations is contained in Section 2. The final result of the simplifications yielded the 10-term correlation equation briefly described in Section 2, Table 2-1.

APPENDIX B

FUEL ANALYSES AND COMBUSTION CALCULATION RESULTS

The equation and method used in this study to calculate the NO_x generation rate in each zone required inputs for the equilibrium values of the concentrations of nitrogen and oxygen in the combustion products and the temperature rise due to combustion. For this purpose, nominal natural gas and low-sulfur oil fuel analyses were obtained from the utility. These are listed in Table B-1. The Aerospace N-element chemistry system was used to perform the combustion calculations. Air temperatures were specified at 533 degrees K (500 degrees F) and fuel temperatures at ambient. Pressure was constant at 1 atm. For purposes of this calculation, equivalent fuels were defined as follows:

Natural gas = $C_{1.1103}H_{4.118}O_{0.0427}N_{0.0174}$

Heat of formation = -19.71 kcal/mole of the above equivalent fuel

Stoichiometric A/F ratio = 15.91 by weight

Low-sulfur oil = $C_{0.5647}H_{0.8622}O_{0.0034}N_{0.0014}S_{0.0007}$

Heat of formation = -1.25 kcal/mole of the above equivalent fuel

Stoichiometric A/F ratio = 13.89 by weight

Table B-1. FUEL ANALYSES

Natural gas		Low-sulfur oil	
Constituent	Volume, %	Constituent	Weight, %
CH_4	88.17	C	87.30
C_2H_6	6.04	H_2	11.20
C_3H_8	2.49	S	0.28
C_4H_{10}	0.27	O_2	0.70
C_5H_{12}	0.02	N_2	0.24
CO_2	2.13	H_2O	0.26
N_2	0.87	Ash	0.02
H_2O	0.01	-	-
Total	100.00	Total	100.00

From the equilibrium calculation, the molar concentrations of nitrogen and oxygen were obtained. These concentrations enter the NO_x generation equation, Section 2, Eq. (2-1), in the form:

$$\mathrm{SON} = [N_2][O_2]^{1/2} \tag{B-1}$$

where

$[N_2]$ = the molar concentration of molecular nitrogen (N_2) in the combustion products

$[O_2]$ = the molar concentration of molecular oxygen

The factor SON and the equilibrium combustion temperatures were calculated over a range of A/F ratios and entered into the correlation program in tabular form. These data are listed in Table B-2. The nitrogen in the two fuels was also entered in the program as a fraction of the fuel weight. Initially, until the correlations confirmed that it was not so, the nitrogen in the natural gas, as well as that in the low-sulfur oil, was entered and treated as bound or fuel nitrogen. These values were:

Natural gas:	0.01326
Low-sulfur oil:	0.002532

Early in the correlation studies, the bound nitrogen in the natural gas was changed to zero.

Table B-2. EQUILIBRIUM COMBUSTION INPUTS FOR THE NO_x GENERATION RATE EQUATION

Natural gas			Low-sulfur oil		
A/F ratio[a]	SON	Temperature, °K	A/F ratio[a]	SON	Temperature, °K
9.55	1.348×10^{-4}	1926	8.33	3.498×10^{-4}	2048
11.14	1.031×10^{-3}	2101	9.72	2.678×10^{-3}	2225
12.73	5.501×10^{-3}	2239	11.11	1.319×10^{-2}	2355
14.32	2.395×10^{-2}	2331	12.50	4.181×10^{-2}	2418
15.91 (st.)	6.329×10^{-2}	2332	13.89 (st.)	0.07899	2401
19.09	0.1303	2187	15.28	0.1120	2341
22.27	0.1717	2022	16.67	0.1393	2264
25.46	0.1994	1877	19.45	0.1798	2098
28.64	0.2194	1757	22.22	0.2074	1946
31.82	0.2347	1655	25.00	0.2273	1817
			27.78	0.2423	1708

[a] By weight.

APPENDIX C

INTERMEDIATE DATA CONVERSION AND CORRELATIONS

C.1 INTRODUCTION

At the outset of this study it seemed clear that all of the primary data necessary for the subsequent correlation effort would not be available in all tests and that some primary data would have to be generated from other related data. In many cases, some of the primary data were not recorded in the data logs because other data indicated that the primary data would be in a certain known range. For example, combustion air temperatures might not be recorded when operating at full load because the full load combustion air temperature is known within an acceptable range. For the purposes of this study, however, values had to be filled in for all necessary primary data.

It was also recognized that in exercising the final correlation equations, certain realistic relations between some of the dependent input variables would have to be preserved. For example, when studying the effect of reduced load on NO_x emissions, the performance of the air preheater at reduced load could be simulated by an empirical relation between load and combustion air temperature.

As a result, seven intermediate correlations were established in the data conversion section of the correlation model. Where all inputs to a given relation were available, an empirical equation was established, and the standard deviation of the data from the equation calculated. In preparing the primary data for the final correlation, the data conversion program first evaluated for missing primary data. Where primary data were found missing the available alternative intermediate correlations were evaluated for missing secondary data. Where secondary data were available for more than one alternative intermediate correlation, that one with the smallest standard deviation of the data was selected, and the missing primary data were calculated from the appropriate equation. In actual practice, either sufficient secondary data were available for only one intermediate correlation, or the primary data were rarely missing. Some of the intermediate correlations were useful, however, in other applications.

Finally, some other empirical correlations and theoretical relations were generated for use in data conversion and in exercising the correlation equations. For the purpose of presenting the empirical correlations used and providing information which might be of value to other users, these intermediate correlations are presented in this Appendix.

C.2 FUEL FLOWS

One of the primary input parameters in this study was the fuel flow. Because of its importance, two intermediate correlations were attempted. Correlations of fuel flow with load were obtained for both gas and oil fuels. These equations and the empirical coefficients are listed in Tables C-1 and C-2.

Attempts were also made to generate fuel flows from data on pressure drops across the gas spuds, or rings, and from the oil gun tips and the appropriate flow resistances. In few cases, however, could the gas spud orifice areas or the oil gun tip configurations be positively established, and this approach was abandoned.

The correlation of fuel flows with load were used in a few cases to fill in missing primary data. One area of significance of these data, however, lies in the observation that load divided by the

Table C-1. CORRELATIONS OF NATURAL GAS FLOW WITH LOAD

FGF = APQGF + BPQGF * LOAD
FGF = Natural gas flow, K-SCFH[a]
LOAD = Electrical output, MW
σ = Standard deviation, % of full load fuel flow

Boiler	Full load, ~MW	Data in correlation	APQGF	BPQGF	σ, %
H1	240	11	103.5	8.923	1.1
H2	240	20	84.02	8.765	0.9
H3	240	39	24.20	8.748	1.2
H4	240	12	59.00	8.158	2.7
H5	350	88	128.4	7.765	2.6
H6	350	23	202.6	7.634	1.9
S1	180	7	56.61	8.263	2.7
S2	180	33	21.06	8.436	2.0
L3	82	8	16.23	10.71	2.2

[a] To convert K-SCFH to m^3/hr multiply by 28.32.

Table C-2. CORRELATIONS OF LOW SULFUR OIL FLOW WITH LOAD

FOF = APQOF + BPQOF * LOAD

FOF = Low-sulfur oil flow, k-lb/hr[a]

LOAD = Electrical output, MW

σ = Standard deviation, % of full load fuel flow

Boiler	Full load, ~MW	Data in correlation	APQOF	BPQOF	σ, %
H1	240	12	6.403	0.4654	2.6
H2	240	33	4.076	0.4615	1.0
H3	240	6	9.467	0.4630	3.6
H4	240	8	2.990	0.4777	3.2
H5	350	39	13.69	0.4138	1.2
H6	350	14	0.1347	0.4592	2.1
S1	180	18	3.971	0.4596	2.5
S2	180	23	5.508	0.4281	2.3
L3	82	14	3.062	0.6082	3.7

[a] To convert k-lb/hr to kg/hr multiply by 453.59.

fuel flow is a measure of plant efficiency, in megawatts per unit of fuel flow. Thus, the effects of varying load on plant efficiency can be obtained directly from these empirical equations. In terms of the constants listed in Table C-1, this efficiency expression is

$$\frac{\text{Load}}{\text{Fuel flow}} = \frac{1}{\text{BPQXF}}\left(1 - \frac{\text{APQXF}}{\text{Fuel flow}}\right) \qquad \text{(C-1)}$$

Since for the boilers studied and for both natural gas and oil fuels the APQXF values are positive, the efficiency described by Eq. (C-1) always decreases with load (fuel flow). Values of APQXF and BPQXF are contained in Tables B-1 and B-2.

C.3 AIR FLOWS

Air flows as such were not measured. Air flow could be obtained from an air foil flow indicator, calibrated in terms of percent of rated flow, and an estimate could be made from the forced draft fan electrical current, in amperes. Both of these methods, however, are calibrated using flows calculated from the fuel gas analysis for the A/F ratio and measured fuel flows. This latter method was chosen as the primary calculation of air flow data in this study. It seemed highly likely, and it turned out to be so, that if NO_x measurements were made at all, O_2 and CO_2 measurements would also have been made. Theoretical expressions were derived from the fuel analyses and equilibrium combustion calculations to relate the overall furnace A/F ratio to the O_2/CO_2 ratio measured in the flue gases:

$$\text{AFRG} = 15.91 + 3.501 * O_2/CO_2 \quad \text{for natural gas fuel} \qquad \text{(C-2)}$$

and

$$\text{AFRO} = 13.89 + 4.22 * O_2/CO_2 \quad \text{for oil fuel} \qquad \text{(C-3)}$$

Air flow was calculated from the product of the A/F ratio, from Eq. (C-2) or (C-3), and from the measured fuel flow. Fuel flow measurement accuracy was considered to be within 1 percent. In case the O_2 and CO_2 data were lacking in a significant amount of the data, however, the correlations shown in Tables C-3 and C-4 were generated. They were little used.

C. 4 COMBUSTION AIR TEMPERATURE

The only measurement of combustion air temperature available, except in a few special cases, was the air preheater outlet temperature. The combustion air must travel from the air preheater through considerable air ducting and the windbox before reaching the the burners, but no data were found to correct the air preheater out temperature to burner air temperature. The few windbox temperature measurements available appeared to show contradictory trends. Since the air flows through uninsulated ducts but also along the outside of the boiler water walls, no simple method using available data was discovered to generate a correction method. Throughout this study, then, it was assumed that there was no change in the combustion air temperature from the air preheater outlet to the burners.

Even this temperature, however, was often not recorded. It was also clear that some method of predicting this temperature as a function of load would be necessary in later exercising of the correlation equation. Correlations of combustion air temperature (air preheater outlet) with load were generated, therefore, and are listed in Table C-5. These correlations were useful both in filling out missing primary data, and in performing later studies of the correlation equations.

Table C-3. CORRELATIONS OF COMBUSTION AIR FLOW WITH AIRFOIL PERCENT FLOW INDICATOR

FDFP = 2116. + 5.2 * AFDP

WAT = FDFP * (APQAM + BPQAM * WATAF)/TPA

WAT = Combustion air flow rate, lb/sec

AFDP = Forced draft fan pressure, in. of water

TPA = Combustion air temperature, degrees Rankine

WATAF = Airfoil indicator, % of full air flow

σ = Standard deviation, % of full load air flow

Boiler	Data in correlation	APQAM	BPQAM	σ, %
H1	9	- 3.018	2.769	1.8
H2	19	18.80	2.259	2.7
H3	35	-12.74	2.497	4.6
H4	11	-15.42	2.641	1.5
H5	45	-17.07	3.347	3.2
H6	19	- 2.583	3.072	1.0

To convert from	to	Multiply by
lb	kg	0.4536
gm/cm^2	in. of water	0.3939
°K	°R	1.80

Table C-4. CORRELATIONS OF COMBUSTION AIR FLOW WITH FORCED DRAFT FAN CURRENT

QAFA = APQRA + BPQRA * AFAA + CPQRA * AFAA * AFAA

QAFB = APQRB + BPQRB * AFAB + CPQRB * AFAB * AFAB

WAT = 1.225 * (QAFA + QAFB)

AFAA, AFAB = Forced draft fan current in the A and B fans, amp

WAT = Combustion air flow rate, lb/sec[a]

σ = Standard deviation, % of full load airflow

Boiler	Data in correlation	APQRA	BPQRA	CPQRA
H1	11	-27.75	2.042	-0.004607
H2	20	18.20	1.329	-0.002100
H3	39	-73.98	2.535	-0.005981
H4	12	-79.86	2.781	-0.007385
H5	64	-61.90	1.406	-0.001801
H6	21	-54.39	2.066	-0.003349

Boiler	APQRB	BPQRB	CPQRB	σ, %
H1	-24.80	1.977	-0.004382	1.9
H2	6.068	1.584	-0.003150	3.2
H3	-71.57	2.487	-0.005713	2.2
H4	-85.65	2.854	-0.007709	3.5
H5	-15.23	1.519	-0.002037	2.5
H6	-98.61	2.602	-0.004757	2.8

[a] To convert lb/sec to kg/sec multiply by 0.4536.

Table C-5. CORRELATIONS OF COMBUSTION AIR TEMPERATURE WITH LOAD

TPA = APQRT + BPQRT * LOAD + CPQRT * LOAD * LOAD

TPA = Combustion air temperature (air heater air outlet temperature), °F[a]

LOAD = Electrical output, MW

σ = Standard deviation, % of full load temperature

Boiler	Data in correlation	Full load temperature °F	APQRT	BPQRT	CPQRT	σ, %
H1	9	587	487.3	0.3883	0.0001151	0.5
H2	18	569	486.3	0.4822	-0.0005756	1.3
H3	35	536	479.0	0.02746	0.0008668	1.7
H4	12	531	466.6	0.2480	7.950×10^{-5}	0.04
H5	70	575	361.8	0.6709	-1.717×10^{-4}	3.5
H6	19	572	501.9	0.03082	4.813×10^{-4}	2.6
S1	7	552	422.8	1.079	-0.002005	0.8
S2	33	557	504.7	0.007385	0.001574	1.4
L3	8	627	377.7	2.147	0.01093	0.9

[a] To convert from °F to °K: $T_K = (5/9)(T_F + 460)$.

APPENDIX D

INPUT DATA FOR CORRELATIONS

This Appendix contains the significant input data derived from the 267 tests with natural gas fuel and the 161 tests with low-sulfur oil fuel in 6 of the 7 boilers listed in Section 2, Tables 2-1 and 2-2. The data from 8-gas and 16-oil tests in boiler L3 were omitted because burner admittance data could not be derived from that boiler and that data was not used in this study.

The operating data presented here are largely self-explanatory. The "Air Fuel Ratio" data are A/F ratios by weight. The following conversion rates are given for convenience:

a. To convert from lb/sec to kg/sec multiply by 0.4536

b. To convert from °F to °K: $T_K = (5/9)(T_F + 460)$.

In the burner configuration data, the burners are identified by a numbering system which starts with burner 1, located on the bottom level of the burner array on the extreme left side, as seen when facing the front of the boiler. Subsequent numbering proceeds around the boiler at the bottom level, as seen from the outside of the boiler, until the entire bottom level is accounted for. The next number, is assigned to the burner just above burner 1 and again proceeds around to the right. Figure 2-3 shows this numbering system for the H5/6 boilers.

The individual burners are considered operating fully under one of three conditions:

a. 0 = No flow of either fuel or air
b. 1 = Air flow only (Air)
c. 2 = Both fuel and air (F+A)

While fuel can be shut off reliably, the air flow can only be shut off by poorly sealing air registers. Nevertheless, in this study, when a burner is indicated "0", the air flow is taken as zero. Obviously, if a boiler has less than 24 burners, then burners listed for numbers larger than the maximum for that boiler do not exist, and the fuel and air flow for these burners are both truly zero.

The "NO_x ports" operational designation is the same as that for the burners except, of course, they cannot be designated "2". Again, NO_x port flow is shut off with a damper, which could leak air, but the NO_x port flow is considered zero when designated "0".

For both the burners and the NO_x ports, when a definite effort was made and noted in the data to partially throttle the air flow to some burners or NO_x ports, these tests were omitted from the sample listed in this Appendix and were not used in this study. It was considered impossible, with existing instrumentation, to estimate the degree of throttling. In all cases used in this study, burner registers and NO_x ports are either fully open or fully closed, as best as this can be determined.

Flue gas samples were drawn from the flue gas ducts between the economizers and the air preheaters in each boiler. Primary data used in this study, when available, were from grab samples analyzed by the chemical laboratory of the utility. Laboratory personnel conducted standard analyses of these samples by accepted procedures. NO_x measurements are per ASTM D-1608.

The majority of the emissions data used in this study were from analyses conducted in the Air Quality Control Mobile Laboratory (AQCML). This on-site laboratory consists of a 32-ft trailer containing all necessary monitoring equipment and a complete sample conditioning system. It is capable of sampling 30 different points in the boiler ducts. The AQCML instrumentation includes the following:

a. CO_2: MSA model 300, NDIR, 0 to 20 percent
b. CO: Beckman model 315(s), NDIR, 0 to 400, 0 to 1000, and 0 to 2000 ppm
c. NO: Beckman model 315 (L), NDIR, 0 to 200, 0 to 500, and 0 to 1000 ppm
d. O_2: Beckman model 742, electrochemical, 1, 5, 10, and 25 percent

In addition, some data were from tests conducted on-site by ESSO Research and Engineering Company. The emissions instrumentation used in these tests are described in a report by W. Bartok, A.R. Crawford, and G.J. Piegari, Systematic Field Study of NO_x Emission Control Methods for Utility Boilers, Final Report No. GRU.4G. NOS. 71, NTIS Report No. PB 210-739 (December 1971).

Most of the boilers were equipped for continuous monitoring of CO and NO_x, using MSA Model 300 CO analyzers, Theta Model LS800 ANXR 1 sensors, and EnviroMetrics Model N-76DF NO_x analyzers. Data from these sources were rarely used.

The following pages contain input operating conditions and burner configuration data.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H1

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
1	061571	1	165.	10.	2.15	10.83	150.	19.1	317.	15.6	550.	106.
2	061571	2	302.	10.	1.43	10.93	200.	24.8	406.	16.4	569.	62.
3	061571	3	313.	7.	1.35	10.93	240.	29.3	478.	16.3	587.	0.
4	062471	1	47.	7.	3.60	10.20	80.	10.5	181.	17.1	519.	137.
5	062471	2	47.	45.	1.90	10.45	130.	15.1	266.	16.5	539.	98.
6	062471	3	89.	54.	2.75	10.50	190.	23.5	395.	15.8	564.	54.
7	062471	4	123.	45.	3.10	10.10	220.	27.4	466.	17.0	573.	47.
8	102071	1	74.	10.	7.80	7.30	49.	7.4	145.	19.7	507.	135.
9	102071	2	64.	13.	7.30	9.30	80.	11.1	207.	18.7	519.	102.
10	111671	2	118.	20.	2.55	10.00	230.	23.0	487.	16.8	582.	62.
11	111971	2	157.	30.	2.90	10.25	222.	27.5	466.	16.9	586.	66.

```
NATURAL GAS FUEL                 BURNER CONFIGURATIONS FOR BOILER H1

NO.  DATE  TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

 1 061571 1      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 2 061571 2      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 3 061571 3      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 4 062471 1      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 5 062471 2      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 6 062471 3      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 7 062471 4      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 8 102071 1      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 9 102071 2      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
10 111671 2      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
11 111971 2      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
```

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H2

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
12	040671	1	111.	40.	3.00	9.77	100.	12.5	213.	17.0	530.	126.
13	040671	2	152.	40.	1.50	12.55	172.	21.1	344.	16.3	550.	72.
14	040671	3	359.	40.	1.85	10.95	245.	23.3	483.	16.5	570.	39.
15	041971	1	175.	100.	2.69	10.08	233.	27.9	471.	16.8	567.	35.
16	041971	2	120.	120.	2.65	10.28	232.	27.7	465.	15.8	569.	43.
17	042071	3	240.	30.	2.50	10.13	240.	23.9	484.	16.8	572.	43.
18	042071	4	219.	30.	2.83	10.40	237.	28.7	485.	16.9	570.	39.
19	042071	5	130.	500.	1.93	10.85	237.	23.5	471.	15.5	574.	74.
20	042171	1	71.	80.	2.20	10.70	202.	24.3	403.	16.6	567.	70.
21	042171	2	78.	140.	2.20	10.70	232.	24.3	403.	16.6	564.	70.
22	042171	3	63.	80.	2.15	10.80	202.	24.4	405.	16.6	559.	86.
23	042171	4	114.	130.	2.30	10.80	202.	24.4	406.	16.7	569.	52.
24	042171	5	112.	50.	2.20	10.80	205.	24.4	405.	15.6	566.	62.
25	042171	6	114.	50.	2.20	10.80	205.	24.4	405.	15.6	563.	62.
26	042171	7	116.	30.	2.30	10.70	247.	23.7	494.	16.7	577.	39.
27	042171	8	84.	100.	2.00	10.80	248.	23.8	493.	16.6	567.	39.
28	060871	1	51.	20.	3.43	9.53	80.	10.3	176.	17.2	521.	122.
29	060871	2	46.	93.	2.35	10.30	130.	16.5	275.	16.7	539.	118.
30	060871	3	54.	277.	1.54	10.63	190.	23.7	390.	16.4	538.	74.
31	060871	4	92.	275.	2.00	10.65	240.	23.4	487.	16.6	549.	47.

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NATURAL GAS FUEL                  BURNER CONFIGURATIONS FOR BOILER H2

NO.  DATE  TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

 12 040671 1     2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 13 040671 2     2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 14 040671 3     2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 15 041971 1     2  2  2  2  1  1  1  1  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 16 041971 2     2  2  2  2  1  2  2  1  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 17 042071 3     2  2  2  2  2  2  2  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 18 042071 4     2  1  1  2  2  2  2  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 19 042071 5     2  2  2  2  1  2  2  1  2  1  1  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 20 042171 1     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 21 042171 2     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 22 042171 3     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 23 042171 4     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 24 042171 5     2  2  2  2  1  1  1  1  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 25 042171 6     2  2  2  2  1  1  1  1  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 26 042171 7     2  2  2  2  1  1  1  1  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 27 042171 8     2  2  2  2  1  1  1  1  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 28 060871 1     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 29 060871 2     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 30 060871 3     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 31 060871 4     2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
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NATURAL GAS FUEL

OPERATING DATA FOR BOILER H3

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
32	061171	1	330.	-0.	2.05	9.15	80.	10.5	176.	16.7	487.	68.
33	061171	2	168.	-0.	2.40	10.20	130.	15.2	254.	16.7	497.	67.
34	061171	3	182.	-0.	1.70	10.90	183.	21.1	347.	16.5	513.	54.
35	061171	4	344.	-0.	1.95	10.95	240.	27.8	460.	16.5	536.	21.
36	091371	1	330.	15.	1.86	11.43	210.	24.0	395.	16.5	519.	23.
37	091371	2	379.	6.	1.92	11.57	210.	24.0	396.	16.5	522.	32.
38	091571	1	378.	54.	1.78	11.55	242.	28.5	468.	16.5	584.	25.
39	091571	2	403.	93.	2.78	10.65	237.	28.2	475.	16.8	534.	20.
40	091571	3	319.	73.	3.17	10.33	235.	28.1	477.	17.0	535.	16.
41	091571	4	308.	50.	1.88	11.53	233.	27.7	456.	16.5	540.	26.
42	091571	5	322.	145.	2.90	10.47	238.	27.7	467.	16.9	535.	23.
43	091571	6	270.	71.	4.40	9.73	238.	27.8	487.	17.5	531.	17.
44	091671	1	240.	67.	3.10	10.67	242.	28.5	482.	16.9	532.	21.
45	091671	2	267.	140.	1.73	11.50	240.	28.2	464.	16.4	536.	25.
46	091771	1	140.	64.	2.78	10.95	240.	28.1	472.	16.8	533.	19.
47	091771	2	134.	58.	3.20	10.60	240.	28.1	476.	17.0	534.	19.
48	092171	1	114.	19.	3.30	9.60	78.	9.4	160.	17.1	488.	76.
49	092171	2	150.	23.	3.65	9.95	143.	16.6	286.	17.2	499.	42.
50	092171	3	210.	60.	3.70	9.80	199.	23.2	400.	17.2	518.	24.
51	092171	4	267.	38.	3.45	9.85	238.	27.9	479.	17.1	530.	18.
52	092271	1	134.	13.	6.95	8.40	81.	9.6	181.	18.8	489.	73.
53	092271	2	171.	20.	2.25	10.85	143.	16.6	276.	16.6	510.	53.
54	092271	3	303.	66.	1.86	11.25	199.	22.9	378.	16.5	513.	25.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H3

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
55	092271	4	169.	62.	2.93	11.07	241.	28.2	475.	16.8	524.	21.
56	092371	2	53.	46.	4.47	9.93	85.	9.8	171.	17.5	487.	0.
57	092371	3	54.	28.	3.13	10.25	140.	16.3	278.	17.0	503.	0.
58	092371	4	104.	136.	2.49	10.97	200.	22.9	383.	16.7	516.	0.
59	092371	6	104.	41.	2.26	11.25	200.	23.1	383.	16.6	509.	0.
60	092371	7	155.	72.	2.23	11.33	240.	27.9	464.	16.6	536.	0.
61	092871	1	81.	22.	9.33	7.03	45.	5.3	108.	20.6	478.	98.
62	092871	2	38.	117.	5.48	9.17	84.	10.4	187.	18.0	490.	89.
63	092871	3	79.	65.	4.83	9.45	84.	10.3	182.	17.7	491.	0.
64	092871	4	59.	84.	3.92	10.37	140.	16.6	286.	17.2	501.	0.
65	092871	5	104.	32.	3.82	10.63	200.	23.1	396.	17.2	516.	0.
66	092871	6	135.	87.	3.65	10.60	240.	28.3	485.	17.1	533.	0.
67	093071	1	193.	175.	1.85	10.63	240.	27.4	453.	16.5	523.	0.
68	100171	1	95.	23.	8.76	7.35	50.	6.1	122.	20.1	477.	93.
69	100171	2	120.	25.	5.50	9.25	82.	10.0	180.	18.0	487.	78.
70	100171	3	109.	39.	5.25	9.15	82.	9.5	170.	17.9	489.	75.

NATURAL GAS FUEL

BURNER CONFIGJRATIONS FOR BOILER H3

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
32	061171	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
33	061171	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
34	061171	3	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
35	061171	4	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
36	091371	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
37	091371	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
38	091571	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
39	091571	2	2	2	2	2	1	1	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
40	091571	3	2	2	2	2	1	1	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
41	091571	4	2	2	2	2	2	2	1	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
42	091571	5	2	2	2	2	2	2	2	2	1	1	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
43	091571	6	2	2	2	2	2	2	2	2	1	1	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
44	091671	1	2	2	2	2	2	2	1	2	2	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
45	091671	2	2	2	2	2	2	2	1	2	2	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
46	091771	1	2	2	2	2	2	2	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
47	091771	2	2	2	2	2	2	2	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
48	092171	1	2	2	2	2	2	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
49	092171	2	2	2	2	2	2	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
50	092171	3	2	2	2	2	2	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
51	092171	4	2	2	2	2	2	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	1.
52	092271	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
53	092271	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
54	092271	3	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.

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NATURAL GAS FUEL                         BURNER CONFIGURATIONS FOR BOILER H3

NO.  DATE  TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

55 092271 4      2  2  2  2  2  2  1  1  1  1  2  2  0  0  0  0  0  0  0  0  0  0  0  0    1.
56 092371 2      2  2  2  2  2  2  1  1  1  1  2  2  0  0  0  0  0  0  0  0  0  0  0  0    1.
57 092371 3      2  2  2  2  2  2  1  1  1  1  2  2  0  0  0  0  0  0  0  0  0  0  0  0    1.
58 092371 4      2  2  2  2  2  2  1  1  1  1  2  2  0  0  0  0  0  0  0  0  0  0  0  0    1.
59 092371 6      2  2  2  2  1  1  2  2  2  2  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
60 092371 7      2  2  2  2  1  1  2  2  2  2  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
61 092871 1      0  0  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
62 092871 2      0  0  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
63 092871 3      2  2  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
64 092871 4      2  2  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
65 092871 5      2  2  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
66 092871 6      2  2  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
67 093071 1      2  2  2  2  2  2  2  2  2  2  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
68 100171 1      0  0  0  0  2  2  2  2  2  2  1  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
69 100171 2      0  0  0  0  2  2  2  2  2  2  1  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
70 100171 3      2  2  2  2  2  2  2  2  2  2  1  1  0  0  0  0  0  0  0  0  0  0  0  0    1.
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NATURAL GAS FUEL

OPERATING DATA FOR BOILER H4

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
71	051171	1	99.	-0.	6.95	7.50	80.	9.2	177.	19.2	487.	50.
72	051171	2	144.	-0.	3.10	10.15	130.	14.8	252.	17.0	500.	46.
73	051171	3	186.	-0.	1.85	10.70	180.	20.1	332.	16.5	514.	43.
74	051171	4	326.	-0.	2.10	10.45	240.	27.3	454.	16.6	531.	0.
75	052771	2	153.	-0.	2.67	9.90	130.	15.2	255.	16.9	500.	43.
76	052771	3	230.	-0.	2.40	10.35	180.	20.8	347.	16.7	514.	38.
77	052771	4	373.	-0.	2.10	10.50	240.	27.7	460.	16.6	531.	0.
78	061171	1	330.	-0.	2.05	10.45	243.	26.4	439.	16.6	531.	0.
79	061171	2	200.	-0.	1.60	10.40	181.	20.3	334.	16.5	514.	43.
80	061171	3	161.	-0.	2.05	10.20	133.	14.6	243.	16.6	501.	74.
81	061171	4	125.	-0.	5.65	8.40	80.	9.4	171.	18.3	487.	94.
82	051172	1	203.	-0.	3.75	9.35	231.	23.7	411.	17.3	528.	0.

NATURAL GAS FUEL

BURNER CONFIGURATIONS FOR BOILER H4

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
71	051171	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
72	051171	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
73	051171	3	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
74	051171	4	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
75	052771	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
76	052771	3	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
77	052771	4	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
78	061171	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
79	061171	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
80	061171	3	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
81	051171	4	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
82	051172	1	2	2	2	2	2	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	1.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H5

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
83	081569	1	268.	-0.	1.95	10.55	177.	19.1	316.	16.6	475.	93.
84	081569	2	472.	-0.	1.83	10.59	261.	27.0	446.	16.5	525.	29.
85	081569	3	685.	-0.	1.53	10.73	351.	36.5	600.	16.4	545.	0.
86	081569	4	160.	-0.	1.98	10.53	178.	19.1	317.	16.6	476.	94.
87	081569	5	270.	-0.	1.94	10.53	261.	27.1	449.	16.6	525.	29.
88	081569	6	356.	-0.	1.85	10.58	352.	36.7	607.	16.5	545.	0.
89	082069	7	257.	-0.	1.70	10.65	155.	16.6	274.	16.5	462.	119.
90	082069	8	440.	-0.	1.72	10.60	262.	26.9	443.	16.5	526.	69.
91	082069	9	532.	-0.	1.11	10.90	352.	35.3	591.	16.3	577.	0.
92	082069	10	158.	-0.	1.45	10.76	155.	15.6	272.	16.4	462.	127.
93	082069	11	236.	-0.	1.72	10.64	260.	27.0	445.	16.5	525.	67.
94	082069	12	322.	-0.	1.59	10.70	352.	36.2	594.	16.4	577.	0.
95	082669	13	280.	-0.	4.00	9.72	174.	18.8	327.	17.4	473.	83.
96	082669	14	513.	-0.	3.40	9.96	259.	26.6	455.	17.1	523.	29.
97	082669	15	784.	-0.	2.68	10.25	351.	36.2	610.	16.8	576.	0.
98	082669	16	243.	-0.	3.85	9.79	175.	18.9	327.	17.3	474.	87.
99	082669	17	343.	-0.	3.31	9.99	257.	26.6	454.	17.1	523.	29.
100	082669	18	467.	-0.	3.15	10.06	350.	36.2	616.	17.0	576.	0.
101	082969	19	543.	-0.	2.01	10.52	352.	36.7	609.	16.6	580.	0.
102	082969	20	491.	-0.	1.53	10.72	354.	37.2	610.	16.4	580.	0.
103	082969	21	596.	-0.	2.99	10.13	351.	36.7	622.	16.9	580.	0.
104	082969	22	354.	-0.	2.31	10.40	350.	36.5	609.	16.7	585.	0.
105	082969	23	298.	-0.	1.58	10.70	351.	36.8	605.	16.4	585.	0.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H5

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
106	082969	24	443.	-0.	3.09	10.09	351.	36.8	626.	17.0	585.	0.
107	012071	9L1	437.	-0.	2.65	10.30	350.	37.6	632.	16.8	585.	0.
108	012071	8L2	919.	-1.	2.30	10.45	350.	37.8	631.	16.7	585.	0.
109	012071	1A	572.	30.	1.92	10.58	350.	37.8	626.	16.5	588.	0.
110	012071	1B	343.	30.	2.38	10.43	350.	38.0	634.	16.7	588.	0.
111	012171	2A	381.	20.	2.35	10.43	350.	35.9	600.	16.7	580.	0.
112	012171	2B	203.	47.	1.45	10.60	350.	37.4	620.	16.6	580.	0.
113	012171	3A	583.	41.	1.75	10.68	350.	37.7	621.	16.5	575.	0.
114	012271	3B	351.	50.	2.05	10.48	350.	38.0	630.	16.6	580.	0.
115	012271	4A	522.	35.	2.00	10.73	350.	37.8	627.	16.6	575.	0.
116	012271	4B	228.	35.	2.18	10.53	350.	37.8	629.	16.6	575.	0.
117	012571	5A	380.	66.	1.93	10.73	350.	38.9	643.	16.5	570.	0.
118	012571	5B	222.	98.	2.00	10.30	350.	38.5	639.	16.6	580.	0.
119	012571	6A	280.	53.	2.23	10.48	349.	38.2	637.	16.7	580.	0.
120	012571	6B	205.	183.	2.35	10.43	350.	38.2	638.	16.7	580.	0.
121	012571	7A	516.	35.	2.15	10.73	350.	38.0	631.	16.6	580.	0.
122	012571	7B	293.	34.	2.30	10.53	350.	38.0	633.	16.7	580.	0.
123	012671	8A	435.	13.	1.60	10.23	350.	38.2	629.	16.5	580.	0.
124	012671	8B	205.	15.	2.35	10.20	350.	38.4	641.	16.7	580.	0.
125	012671	9A	423.	20.	2.18	11.73	350.	38.0	629.	16.6	578.	0.
126	012671	9B	217.	20.	2.15	10.60	350.	38.0	631.	16.6	580.	0.
127	012671	10A	454.	4.	1.80	10.53	350.	37.8	625.	16.5	580.	0.
128	C12671	10B	262.	21.	2.10	10.63	350.	37.8	628.	16.6	580.	0.

NATURAL GAS FUEL .

OPERATING DATA FOR BOILER H5

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
129	020171	11A	261.	212.	2.53	10.18	350.	38.5	646.	16.8	575.	0.
130	020171	12A	236.	-0.	3.65	9.75	350.	38.6	664.	17.2	575.	0.
131	020271	12B	186.	40.	3.19	9.95	350.	38.7	659.	17.0	575.	0.
132	020271	13A	313.	39.	2.33	10.30	350.	38.6	644.	16.7	575.	0.
133	020271	13B	225.	70.	2.45	10.23	350.	38.6	646.	16.8	575.	0.
134	020271	14A	243.	115.	2.68	10.23	350.	38.6	649.	15.8	575.	0.
135	020271	14B	193.	78.	3.68	9.78	350.	38.7	668.	17.2	575.	0.
136	022571	1	345.	70.	1.50	10.80	350.	38.6	632.	16.4	575.	0.
137	022571	2	199.	70.	2.20	10.40	350.	38.9	647.	16.7	575.	0.
138	022571	3	372.	20.	1.85	10.60	350.	38.9	642.	16.5	580.	0.
139	022571	4	640.	20.	1.35	10.80	350.	38.7	634.	16.3	580.	0.
140	022571	5	380.	20.	2.40	10.40	350.	38.9	650.	16.7	575.	0.
141	022571	6	477.	20.	2.80	10.30	350.	38.9	656.	16.9	580.	0.
142	022571	11	241.	20.	3.60	9.80	350.	38.9	669.	17.2	580.	0.
143	022671	17	246.	20.	1.30	10.70	153.	18.6	304.	16.3	415.	113.
144	022671	18	54.	20.	2.40	10.40	151.	18.5	309.	16.7	420.	112.
145	022671	14	85.	20.	2.70	11.80	152.	18.5	308.	16.7	385.	0.
146	022671	16	303.	20.	2.10	12.20	152.	18.5	305.	16.5	385.	0.
147	022671	15	172.	20.	2.20	12.10	153.	18.3	303.	16.5	495.	86.
148	022671	13	80.	20.	2.10	12.10	152.	18.3	303.	16.5	495.	85.
149	022671	19	136.	20.	2.10	12.00	151.	18.1	299.	16.5	459.	86.
150	022671	20	105.	20.	1.90	12.30	153.	17.9	295.	16.5	500.	86.
151	030871	1	43.	-0.	1.65	10.80	147.	16.6	273.	15.4	493.	84.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H5

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
152	030871	2	60.	-0.	1.55	10.75	199.	21.6	354.	16.4	500.	0.
153	030871	3	97.	-0.	1.85	10.45	250.	26.3	435.	16.5	528.	0.
154	030871	4	153.	-0.	2.15	10.40	238.	30.4	506.	16.6	558.	0.
155	030871	5	256.	-0.	2.40	10.15	350.	36.9	616.	16.7	578.	0.
156	032671	1	217.	-0.	3.10	9.90	150.	15.8	269.	17.0	495.	82.
157	032671	2	357.	-0.	3.20	9.80	250.	25.0	427.	17.1	525.	0.
158	032671	3	504.	-0.	2.60	10.20	350.	35.6	598.	16.8	570.	0.
159	072771	1	150.	55.	1.60	11.80	300.	32.3	531.	16.4	548.	0.
160	072771	2	169.	125.	1.90	11.80	300.	32.4	534.	16.5	548.	0.
161	072771	3	170.	60.	1.90	11.80	300.	32.4	534.	16.5	548.	0.
162	072771	4	159.	30.	2.20	11.50	300.	32.4	537.	16.6	548.	0.
163	072771	5	280.	4.	2.00	11.60	300.	32.4	535.	16.5	548.	0.
164	072771	6	210.	40.	1.90	11.90	300.	32.4	534.	16.5	548.	0.
165	072771	7	220.	80.	2.20	11.80	350.	37.5	621.	16.6	576.	0.
166	072871	1	300.	-0.	2.90	10.17	300.	32.4	548.	16.9	548.	0.
167	072871	3	150.	47.	3.10	10.60	300.	32.4	549.	16.9	548.	0.
168	072871	4	220.	15.	3.00	11.00	350.	37.5	633.	16.9	576.	0.
169	072871	5	340.	-0.	3.00	10.13	350.	37.5	636.	16.9	576.	0.
170	080471	2	245.	-0.	2.65	11.20	250.	27.3	457.	16.7	519.	0.
171	080471	3	96.	-0.	2.65	11.20	250.	27.3	457.	16.7	519.	0.
172	080471	4	106.	-0.	2.65	11.20	250.	27.3	457.	16.7	519.	0.
173	080471	5	165.	-0.	2.55	11.30	250.	27.3	456.	16.7	519.	0.
174	080571	1	315.	-0.	3.00	11.00	250.	27.3	460.	16.9	519.	0.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H5

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
175	080571	2	215.	-0.	3.20	11.00	250.	27.3	462.	16.9	519.	0.
176	080571	3	115.	25.	3.20	11.40	250.	27.3	461.	16.9	519.	0.
177	080571	4	223.	50.	2.80	11.80	350.	37.5	628.	16.7	576.	0.
178	080571	5	210.	0.	2.90	11.80	325.	35.0	586.	16.8	562.	0.
179	080571	6	180.	-0.	3.00	11.80	300.	32.4	544.	16.8	548.	0.
180	080571	7	144.	-0.	2.70	11.80	265.	28.6	482.	16.7	528.	0.
181	080571	8	96.	-0.	2.60	12.00	240.	25.3	438.	16.7	513.	0.
182	080571	9	85.	-0.	3.10	11.90	210.	23.2	390.	16.8	495.	0.
183	080571	10	67.	-0.	2.60	12.60	175.	19.6	326.	16.6	474.	0.
184	080571	11	60.	-0.	2.60	12.40	150.	17.0	284.	16.6	459.	40.
185	080571	12	158.	-0.	4.50	9.52	150.	17.0	299.	17.6	459.	40.
186	080571	13	190.	-0.	4.00	9.72	150.	17.0	296.	17.4	459.	40.
187	102572	1	95.	-0.	3.75	9.80	155.	18.1	313.	17.3	480.	40.
188	102572	2	110.	-0.	4.20	9.60	200.	24.1	420.	17.4	498.	0.
189	102572	3	150.	-0.	3.90	10.00	252.	28.3	490.	17.3	518.	0.
190	102572	4	223.	-0.	3.80	10.20	305.	33.9	584.	17.2	538.	0.
191	102572	5	330.	-0.	3.90	10.20	305.	33.9	584.	17.3	538.	0.
192	020173	1	140.	15.	5.10	9.40	181.	19.8	352.	17.8	493.	0.
193	020173	2	90.	15.	5.70	9.00	181.	20.4	370.	18.1	493.	0.
194	020173	3	149.	15.	5.25	9.23	251.	29.0	519.	17.9	508.	0.
195	020173	4	185.	25.	4.85	9.30	304.	33.0	584.	17.7	515.	0.
196	020173	5	387.	25.	4.20	10.00	351.	37.6	653.	17.4	565.	0.
197	020173	6	265.	18.	4.90	9.30	349.	37.6	667.	17.8	565.	0.

NATURAL GAS FUEL

BURNER CONFIGURATIONS FOR BOILER H5

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
83	081569	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
84	081569	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
85	081569	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
86	081569	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
87	081569	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
88	081569	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
89	082069	7	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
90	082069	8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
91	082069	9	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
92	082069	10	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
93	082069	11	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
94	082069	12	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
95	082669	13	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
96	082669	14	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
97	082669	15	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
98	082669	16	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
99	082669	17	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
100	082669	18	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
101	082969	19	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
102	082969	20	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
103	082969	21	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
104	082969	22	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
105	082969	23	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.

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NATURAL GAS FUEL                    BURNER CONFIGJRATIONS FOR BOILER H5

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

106 082969 24     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
107 012071 BL1    2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
108 012071 BL2    2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     0.
109 012071 1A     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     0.
110 012071 1B     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
111 012171 2A     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1     0.
112 012171 2B     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1     1.
113 012171 3A     1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2     0.
114 012271 3B     1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2     1.
115 012271 4A     2  2  1  1  2  2  2  2  1  1  2  2  2  2  1  1  2  2  2  2  1  1  2  2     0.
116 012271 4B     2  2  1  1  2  2  2  2  1  1  2  2  2  2  1  1  2  2  2  2  1  1  2  2     1.
117 012571 5A     2  2  2  2  2  2  1  1  2  2  1  1  2  2  2  2  1  1  2  2  1  1  2  2     0.
118 012571 5B     2  2  2  2  2  2  1  1  2  2  1  1  2  2  2  2  1  1  2  2  1  1  2  2     1.
119 012571 6A     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  1  1  1  1     0.
120 012571 6B     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  1  1  1  1     1.
121 012571 7A     2  2  2  2  1  1  1  1  1  1  1  1  2  2  2  2  2  2  2  2  2  2  2  2     0.
122 012571 7B     2  2  2  2  1  1  1  1  1  1  1  1  2  2  2  2  2  2  2  2  2  2  2  2     1.
123 012671 8A     2  2  2  2  1  2  1  2  1  2  1  2  2  2  2  2  1  2  1  2  1  2  1  2     0.
124 012671 8B     2  2  2  2  1  2  1  2  1  2  1  2  2  2  2  2  1  2  1  2  1  2  1  2     1.
125 012671 9A     2  2  2  2  1  2  1  2  2  1  2  1  2  2  2  2  2  1  2  1  1  2  1  2     0.
126 012671 9B     2  2  2  2  1  2  1  2  2  1  2  1  2  2  2  2  2  1  2  1  1  2  1  2     1.
127 012671 10A    2  2  2  2  2  1  2  1  1  2  1  2  2  2  2  2  2  1  2  1  1  2  1  2     0.
128 012671 10B    2  2  2  2  2  1  2  1  1  2  1  2  2  2  2  2  2  1  2  1  1  2  1  2     1.
```

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 NATURAL GAS FUEL                    BURNER CONFIGURATIONS FOR BOILER H5

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

129 020171 11A    2  2  2  2  2  2  2  2  2  2  2  2  1  1  2  2  1  1  2  2  1  1  2  2     0.
130 020171 12A    2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  1  2  2  1  1  1  1  1  1     0.
131 020271 12B    2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  1  2  2  1  1  1  1  1  1     1.
132 020271 13A    2  2  2  2  2  2  2  2  2  2  2  2  1  2  1  2  1  2  1  2  1  1  1  1     0.
133 020271 13B    2  2  2  2  2  2  2  2  2  2  2  2  1  2  1  2  1  2  1  2  1  1  1  1     1.
134 020271 14A    2  2  2  2  2  2  2  2  2  2  2  2  2  1  2  1  2  1  2  1  1  1  1  1     0.
135 020271 14B    2  2  2  2  2  2  2  2  2  2  2  2  2  1  2  1  2  1  2  1  1  1  1  1     1.
136 022571 1      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     0.
137 022571 2      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     1.
138 022571 3      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
139 022571 4      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     0.
140 022571 5      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     0.
141 022571 6      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
142 022571 11     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     1.
143 022671 17     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     0.
144 022671 18     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     1.
145 022671 14     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     1.
146 022671 16     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     0.
147 022671 15     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
148 022671 13     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     0.
149 022671 19     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
150 022671 20     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     0.
151 030871 1      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  1  2  2  1  2  1  1     1.
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NATURAL GAS FUEL

BURNER CONFIGJRATIONS FOR BOILER H5

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
152	030871	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	1	2	2	1	2	1	1	1.
153	030871	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	1	2	2	1	2	1	1	1.
154	030871	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	1	2	2	1	2	1	1	1.
155	030871	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	1	2	2	1	2	1	1	1.
156	032671	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
157	032671	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
158	032671	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
159	072771	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
160	072771	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	1	2	2	1	2	1	1	1.
161	072771	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
162	072771	4	2	2	2	2	2	2	2	2	1	2	1	2	2	2	2	2	2	1	2	1	1	1	1	1	1.
163	072771	5	2	2	2	2	2	2	2	2	1	2	1	2	2	2	2	2	2	1	2	1	1	1	1	1	0.
164	072771	6	2	2	2	2	2	2	2	2	1	2	1	2	2	2	2	2	2	1	2	1	1	1	1	1	-0.
165	072771	7	2	2	2	2	2	2	2	2	1	2	1	2	2	2	2	2	2	1	2	1	1	1	1	1	1.
166	072871	1	2	2	2	2	2	1	2	1	2	1	2	1	2	2	2	2	2	1	2	1	2	1	2	1	0.
167	072871	3	2	2	2	2	2	2	2	2	2	2	1	1	2	2	2	2	1	1	2	2	1	1	1	1	0.
168	072871	4	2	2	2	2	2	2	2	2	2	2	1	1	2	2	2	2	1	1	2	2	1	1	1	1	1.
169	072871	5	2	2	2	2	2	2	2	2	2	2	1	1	2	2	2	2	1	1	2	2	1	1	1	1	0.
170	030471	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
171	030471	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
172	030471	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
173	080471	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
174	080571	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.

NATURAL GAS FUEL

BURNER CONFIGJRATIONS FOR BOILER H5

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
175	080571	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
176	080571	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
177	080571	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
178	080571	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
179	080571	6	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
180	080571	7	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
181	080571	8	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
182	080571	9	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
183	080571	10	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
184	080571	11	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
185	080571	12	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
186	080571	13	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
187	102572	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	0.
188	102572	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
189	102572	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
190	102572	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
191	102572	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	0.
192	020173	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	0.
193	020173	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
194	020173	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
195	020173	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
196	020173	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	0.
197	020173	6	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H6

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
198	051371	1	490.	-0.	2.61	10.24	350.	36.9	620.	16.8	572.	0.
199	051471	1	267.	35.	2.45	10.45	150.	18.2	304.	16.7	520.	84.
200	051471	2	255.	40.	2.30	10.40	200.	22.4	374.	16.7	540.	0.
201	051471	3	330.	40.	2.18	10.60	250.	27.3	455.	16.6	543.	0.
202	051471	4	348.	40.	2.30	10.30	300.	31.6	528.	16.7	555.	0.
203	051471	5	496.	40.	2.73	10.43	350.	36.9	621.	16.8	580.	0.
204	051971	1	258.	30.	2.25	10.48	350.	37.6	626.	16.7	575.	0.
205	051971	2	306.	50.	2.23	10.48	350.	37.3	621.	16.7	572.	0.
206	051971	3	328.	20.	2.05	10.83	350.	37.4	620.	16.6	572.	0.
207	051971	4	257.	-0.	2.08	10.63	350.	37.4	621.	16.6	585.	0.
208	052071	1	243.	30.	2.40	10.30	350.	37.8	633.	16.7	580.	0.
209	052071	2	309.	15.	2.10	10.50	350.	37.6	624.	16.6	572.	0.
210	052871	1	57.	60.	1.23	10.90	150.	17.8	290.	16.3	510.	82.
211	052871	2	164.	50.	1.95	10.70	250.	27.7	458.	16.6	530.	0.
212	052871	3	227.	60.	2.08	10.38	300.	32.6	542.	16.6	550.	0.
213	052871	4	305.	80.	2.10	10.60	350.	38.5	639.	16.6	588.	0.
214	052871	5	336.	70.	2.18	10.48	350.	38.4	638.	16.6	590.	0.
215	081871	1	160.	35.	2.40	11.20	275.	30.7	512.	16.7	550.	0.
216	081871	2	218.	35.	2.50	11.20	300.	33.6	561.	16.7	545.	0.
217	081871	3	210.	-0.	2.40	11.40	300.	33.6	560.	16.6	550.	0.
218	081871	4	270.	45.	2.60	11.00	350.	39.5	662.	16.7	565.	0.
219	081871	5	260.	25.	2.30	13.80	350.	39.5	652.	16.5	575.	0.
220	120271	1	483.	15.	3.15	10.55	350.	37.9	642.	17.0	572.	0.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER H6

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
221	120271	2	910.	15.	3.00	10.70	350.	37.9	640.	16.9	572.	0.
222	120271	3	795.	19.	2.70	10.80	350.	37.9	636.	16.8	572.	0.
223	120271	4	780.	17.	2.50	10.80	350.	37.9	634.	16.7	572.	0.
224	120271	5	590.	20.	2.50	10.80	350.	37.9	634.	16.7	572.	0.
225	120271	6	610.	20.	2.30	10.80	350.	37.9	631.	16.7	572.	0.
226	120271	7	308.	20.	2.50	10.60	350.	37.9	634.	16.7	572.	0.
227	071972	1	208.	10.	2.51	11.00	348.	38.6	644.	16.7	523.*	0.

* Some Air Preheater Baskets Removed

NATURAL GAS FUEL

BURNER CONFIGJRATIONS FOR BOILER H6

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
198	051371	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
199	051471	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
200	051471	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
201	051471	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
202	051471	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
203	051471	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
204	051971	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
205	051971	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	2	1	2	1	1.
206	051971	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	2	1	2	1.
207	051971	4	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	1.
208	052071	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
209	052071	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	2	1	2	1.
210	052671	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
211	052871	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
212	052871	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
213	052871	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
214	052871	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	1	2	1	2	2	1	2	1	1.
215	081871	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
216	081971	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
217	081871	3	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
218	081871	4	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
219	081871	5	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.
220	120271	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.

NATURAL GAS FUEL

BURNER CONFIGURATIONS FOR BOILER H6

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
221	120271	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
222	120271	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
223	120271	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
224	120271	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
225	120271	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0.
226	120271	7	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1.
227	071972	1	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1.

NATURAL GAS FUEL

OPERATING DATA FOR BOILER S1

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
228	111270	1B	61.	-3.	2.93	10.66	50.	6.6	112.	16.9	470.	38.
229	111270	2B	56.	-3.	2.23	10.40	70.	8.5	143.	16.7	490.	50.
230	111270	3C	63.	-0.	1.63	10.96	90.	10.0	165.	16.4	505.	40.
231	111370	4B	112.	-0.	1.33	11.02	121.	13.7	225.	16.4	525.	12.
232	111370	5	141.	-3.	1.40	11.02	143.	16.5	269.	16.4	535.	10.
233	111370	6	176.	-3.	1.45	11.20	180.	19.9	326.	15.4	561.	0.
234	110371	4	151.	-0.	2.06	10.80	180.	21.4	355.	16.5	545.	0.

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NATURAL GAS FUEL                  BURNER CONFIGURATIONS FOR BOILER S1

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

228 111270 1B     2  2  2  2  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
229 111270 2B     2  2  2  2  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0   -0.
230 111270 3B     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0   -0.
231 111370 41     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
232 111370 3      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
233 111370 5      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
234 110871 4      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
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NATURAL GAS FUEL

OPERATING DATA FOR BOILER S2

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
235	100970	1A	182.	20.	2.71	10.43	180.	20.4	344.	16.8	565.	38.
236	100970	2A	171.	61.	1.24	11.40	181.	20.4	333.	16.3	550.	0.
237	100970	3A	145.	75.	2.15	10.65	182.	20.4	340.	16.5	550.	0.
238	100970	4A	178.	60.	3.35	9.98	176.	19.9	337.	17.1	540.	0.
239	100970	5	306.	35.	1.13	11.16	172.	19.4	316.	16.3	542.	0.
240	110470	0	97.	-0.	3.23	9.95	43.	5.0	85.	17.1	522.	56.
241	110470	1	61.	-0.	3.43	10.17	44.	5.3	91.	17.2	495.	44.
242	110470	2	63.	-0.	2.80	10.45	69.	7.4	124.	16.9	505.	37.
243	110470	3	60.	-0.	1.90	11.10	82.	9.8	161.	16.5	505.	25.
244	110570	0	119.	-0.	1.78	10.90	81.	9.6	159.	16.5	525.	35.
245	110570	4	52.	-0.	1.85	11.03	80.	9.5	157.	16.5	510.	38.
246	110570	6	83.	-0.	1.33	11.23	120.	13.8	228.	16.3	527.	10.
247	110570	7	117.	-0.	1.30	11.33	150.	17.4	295.	16.4	542.	0.
248	110570	8A	133.	-0.	1.78	11.25	160.	19.9	323.	16.2	555.	0.
249	110670	8B	144.	-0.	1.25	11.20	181.	20.0	327.	16.3	550.	0.
250	110970	10A	58.	-0.	2.33	10.35	60.	7.2	121.	16.7	510.	64.
251	110970	10B	72.	-0.	1.90	10.85	61.	9.9	161.	16.5	525.	58.
252	020471	2	113.	30.	1.24	11.19	70.	8.4	137.	16.3	525.	52.
253	020471	3	200.	35.	1.06	11.34	119.	13.8	225.	16.2	525.	52.
254	020471	4	125.	-0.	3.08	10.53	120.	13.2	223.	16.9	530.	8.
255	020471	5	157.	-0.	1.67	11.49	182.	20.4	335.	16.4	560.	0.
256	020471	6	181.	-0.	3.22	10.72	181.	20.3	344.	17.0	557.	0.
257	020471	7	377.	-0.	2.75	10.94	180.	20.3	341.	16.8	562.	0.

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NATURAL GAS FUEL                     BURNER CONFIGURATIONS FOR BOILER S2

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

235 100970 1A     2  2  2  2  1  2  2  1  2  1  1  2  2  2  2  2  0  0  0  0  0  0  0  0     0.
236 100970 2A     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
237 100970 3A     2  2  2  2  2  1  1  2  2  2  2  2  1  2  2  1  0  0  0  0  0  0  0  0     0.
238 100970 4A     2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0     0.
239 100970 5      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0     0.
240 110470 0      0  0  0  0  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
241 110470 1      0  0  0  0  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
242 110470 2      0  0  0  0  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
243 110470 3      0  0  0  0  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
244 110570 4      0  0  0  0  2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0     0.
245 110570 5      0  0  0  0  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
246 110570 6      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
247 110570 7      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
248 110670 8A     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
249 110670 8B     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
250 110970 10A    2  2  2  2  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
251 110970 10B    2  2  2  2  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
252 020471 2      0  0  0  0  2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0     0.
253 020471 3      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0     0.
254 020471 4      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
255 020471 5      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
256 020471 6      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0     0.
257 020471 7      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0     0.
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NATURAL GAS FULL

OPERATING DATA FOR BOILER S2

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
258	020471	8	347.	-0.	1.13	11.96	181.	20.3	330.	16.2	563.	0.
259	020571	9	110.	30.	3.06	10.37	70.	7.2	123.	16.9	507.	32.
260	020571	10	68.	-0.	1.70	11.08	70.	7.2	118.	16.4	510.	42.
261	020571	11	94.	-0.	1.14	11.27	121.	13.6	221.	16.3	525.	9.
262	020571	12	227.	30.	2.33	10.66	121.	13.8	231.	16.7	540.	10.
263	020571	13	359.	70.	1.05	7.90	179.	20.0	328.	16.4	563.	0.
264	020571	14	373.	30.	2.78	10.59	181.	20.3	342.	16.8	565.	0.
265	020571	15	187.	-0.	3.05	10.39	180.	20.0	379.	16.9	560.	0.
266	020571	16	157.	10.	1.65	11.27	181.	20.1	330.	16.4	558.	0.
267	110971	3	144.	-0.	4.30	10.25	185.	22.1	385.	17.4	568.	0.

NATURAL GAS FUEL BURNER CONFIGURATIONS FOR BOILER S2

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
258	020471	8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
259	020571	9	0	[illegible]	0	[illegible]	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
260	020571	10	2	2	2	2	0	0	0	0	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
261	020571	11	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
262	020571	12	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
263	020571	13	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
264	020571	14	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
265	020571	15	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
266	020571	15	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
267	110871	3	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER #1

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
1	062271	1	278.	14.	3.35	14.30	90.	13.1	194.	14.9	520.	151.
2	062271	2	289.	23.	1.73	14.13	140.	19.4	280.	14.6	545.	141.
3	062271	3	333.	15.	1.70	14.43	190.	26.4	390.	14.4	574.	122.
4	062271	4	380.	15.	1.68	14.28	230.	31.9	461.	14.4	598.	137.
5	062371	1	146.	22.	3.38	13.33	90.	13.6	224.	15.0	513.	137.
6	062371	2	153.	33.	2.68	13.53	130.	18.9	279.	14.7	542.	129.
7	062371	3	177.	15.	2.05	13.80	180.	25.6	378.	14.8	569.	126.
8	062371	4	198.	13.	2.70	13.60	225.	31.1	458.	14.7	595.	137.
9	111671	1	211.	25.	3.00	13.60	232.	31.7	471.	14.9	530.	62.
10	111971	1	250.	25.	4.65	12.05	217.	30.6	474.	15.5	530.	102.
11	012773	1	234.	40.	4.93	11.90	227.	30.6	478.	15.7	597.	151.
12	012773	2	209.	40.	4.25	13.40	224.	29.7	453.	15.2	595.	157.

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LOW SULFUR OIL FUEL                  BURNER CONFIGURATIONS FOR BOILER 41

NO.  DATE  TEST   1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

 1 062271 1       2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 2 062271 2       2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 3 062271 3       2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 4 062271 4       2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0    0.
 5 062371 1       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 6 062371 2       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 7 062371 3       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 8 062371 4       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
 9 111671 1       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
10 111971 1       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
11 012773 1       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
12 012773 2       2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0    0.
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LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER H2

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
13	041271	1	333.	30.	1.70	13.20	240.	31.9	461.	14.4	580.	98.
14	041271	2	273.	30.	2.00	12.90	165.	21.4	311.	14.5	568.	153.
15	041271	3	234.	30.	4.50	11.70	89.	12.5	194.	15.5	534.	161.
16	041371	1	178.	30.	2.73	13.50	230.	30.6	450.	14.7	582.	129.
17	041371	2	248.	40.	3.60	13.00	227.	30.0	452.	15.1	578.	129.
18	041371	3	229.	20.	2.63	13.95	232.	31.1	457.	14.7	579.	133.
19	041471	4	284.	40.	2.90	16.03	240.	31.9	468.	14.7	578.	129.
20	041471	5	295.	40.	2.12	15.98	240.	31.7	458.	14.4	581.	129.
21	041471	6	262.	25.	2.98	15.88	232.	31.1	457.	14.7	575.	133.
22	041571	7	210.	30.	2.50	13.68	240.	31.9	468.	14.7	582.	122.
23	041571	8	212.	25.	2.98	13.30	230.	31.1	461.	14.8	578.	122.
24	041671	10	228.	50.	3.05	12.40	228.	30.6	456.	14.9	574.	114.
25	041671	11	237.	60.	3.10	12.50	232.	31.1	465.	14.9	573.	182.
26	041671	12	231.	60.	4.05	12.00	222.	29.7	455.	15.3	569.	110.
27	042671	1	166.	35.	3.10	12.80	195.	26.4	393.	14.9	564.	147.
28	042671	2	165.	35.	3.10	12.80	200.	26.4	393.	14.9	565.	143.
29	042671	3	162.	40.	3.00	12.90	200.	26.7	397.	14.9	565.	147.
30	042671	4	162.	35.	3.00	12.90	200.	26.4	392.	14.9	565.	147.
31	042671	5	200.	30.	3.05	13.00	200.	26.4	393.	14.9	569.	151.
32	042671	6	186.	35.	2.75	13.10	200.	26.4	390.	14.8	565.	149.
33	042671	7	309.	30.	1.70	13.60	200.	26.7	384.	14.4	573.	135.
34	042771	1	172.	35.	4.05	12.53	90.	13.1	199.	15.3	532.	181.
35	042771	2	161.	40.	3.10	13.00	138.	18.9	281.	14.9	538.	157.

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER #2

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
36	042771	3	176.	35.	3.03	13.20	182.	24.2	359.	14.9	563.	145.
37	042771	4	186.	30.	2.73	13.88	240.	32.2	475.	14.7	573.	98.
38	042871	1	251.	30.	3.55	13.08	90.	12.2	183.	15.0	537.	169.
39	042971	2	262.	30.	2.18	13.95	140.	20.0	291.	14.5	551.	161.
40	042871	3	271.	30.	1.50	14.30	190.	25.6	369.	14.4	568.	141.
41	042871	4	314.	30.	1.98	14.20	240.	31.9	462.	14.5	579.	102.
42	111171	1	193.	23.	3.60	13.65	194.	25.0	376.	15.0	565.	145.
43	111171	2	219.	25.	3.80	13.80	230.	31.1	469.	15.1	575.	65.
44	111171	3	185.	23.	3.90	13.70	147.	20.3	305.	15.1	552.	169.
45	111171	4	220.	23.	5.20	12.20	68.	12.8	262.	15.3	534.	151.

LOW SULFUR OIL FUEL

BURNER CONFIGURATIONS FOR BOILER #2

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
13	041271	1	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
14	041271	2	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
15	041271	3	0	0	0	0	0	0	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
16	041371	1	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
17	041371	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
18	041371	3	2	1	1	2	2	2	2	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
19	041471	4	2	2	2	2	2	2	2	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
20	041471	5	2	2	2	2	2	2	2	2	2	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
21	041471	6	2	2	2	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
22	041571	7	2	2	2	2	1	1	1	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
23	041571	8	2	2	2	2	1	2	2	1	2	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
24	041671	10	1	2	2	1	2	2	2	2	2	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
25	041671	11	2	2	2	2	2	1	1	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
26	041671	12	2	2	2	2	1	2	2	1	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
27	042671	1	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
28	042671	2	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
29	042671	3	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
30	042671	4	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
31	042671	5	2	2	2	2	1	1	1	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
32	042671	6	2	2	2	2	1	1	1	1	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
33	042671	7	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
34	042771	1	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.
35	042771	2	2	2	2	2	2	1	1	2	1	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0.

```
LOW SULFUR OIL FUEL              BURNER CONFIGURATIONS FOR BOILER 42

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

 36 042771 3      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0     0.
 37 042771 4      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0     0.
 38 042871 1      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0     0.
 39 042871 2      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0     0.
 40 042871 3      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0     0.
 41 042871 4      2  2  2  2  2  2  2  2  2  2  2  2  0  0  0  0  0  0  0  0  0  0  0  0     0.
 42 111171 1      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0     0.
 43 111171 2      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0     0.
 44 111171 3      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0     0.
 45 111171 4      2  2  2  2  2  1  1  2  1  2  2  1  0  0  0  0  0  0  0  0  0  0  0  0     0.
```

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER 43

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
45	071471	3	198.	-0.	4.95	11.90	142.	21.4	335.	15.5	498.	61.
47	071471	4	234.	-0.	4.95	11.90	142.	21.4	335.	15.5	500.	59.
48	071471	5	234.	-0.	4.10	12.60	170.	23.9	365.	15.3	505.	54.
49	071471	6	206.	-0.	3.95	12.70	170.	23.6	359.	15.2	505.	55.
50	071471	7	243.	-0.	3.90	12.65	225.	31.9	485.	15.2	518.	27.
51	071471	9	285.	-0.	3.75	12.95	226.	31.9	483.	15.1	519.	27.

LOW SULFUR OIL FUEL BURNER CONFIGURATIONS FOR BOILER H3

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
46	071471	3	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
47	071471	4	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
48	071471	5	2	2	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
49	071471	6	2	2	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
50	071471	7	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
51	071471	8	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER #6

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP.(F)	FGR FLOW (LBS/SEC)
52	070971	1	165.	-0.	5.03	11.40	90.	12.5	200.	16.0	491.	120.
53	070971	2	176.	-0.	5.12	10.05	90.	12.5	206.	16.5	491.	120.
54	070971	3	181.	-0.	4.80	12.15	142.	20.0	311.	15.5	502.	82.
55	070971	4	213.	-0.	4.59	12.30	143.	20.0	309.	15.4	502.	82.
56	070971	5	242.	-0.	4.45	12.25	192.	26.7	411.	15.4	515.	48.
57	070971	6	222.	-0.	4.05	12.10	192.	26.7	415.	15.5	515.	47.
58	070971	7	229.	-0.	4.45	12.30	233.	31.9	492.	15.4	528.	5.
59	070971	8	286.	-0.	3.95	12.75	235.	31.4	477.	15.2	529.	3.

LOW SULFUR OIL FUEL BURNER CONFIGURATIONS FOR BOILER H.

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
52	070971	1	0	0	0	0	2	2	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
53	070971	2	0	0	0	0	2	2	0	0	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
54	070971	3	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
55	070971	4	0	0	0	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
56	070971	5	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.
57	070971	6	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
58	070971	7	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	1.
59	070971	8	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0.

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER 45

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
60	022371	0	264.	20.	-0.00	-0.00	250.	32.5	484.	15.0	520.	0.
61	022371	1A	226.	-0.	-0.00	-0.00	250.	31.9	484.	16.5	523.	0.
62	022371	1AA	276.	24.	3.80	13.00	350.	45.0	680.	15.1	563.	0.
63	022371	1B	262.	21.	3.70	13.00	353.	45.0	679.	15.1	565.	0.
64	022471	2A	324.	20.	3.70	12.20	350.	45.0	683.	15.2	565.	0.
65	022471	2B	315.	20.	3.80	12.60	350.	45.0	679.	15.1	563.	0.
66	022471	3A	189.	25.	4.10	12.70	150.	21.9	335.	15.3	515.	111.
67	022471	3B	142.	23.	3.30	12.60	150.	21.9	333.	15.2	510.	114.
68	030171	6	276.	25.	2.40	14.00	348.	43.9	641.	14.5	563.	0.
69	030171	5	320.	20.	1.60	14.60	350.	43.9	630.	14.3	563.	0.
70	030171	1	282.	50.	1.65	14.20	350.	43.6	630.	14.4	555.	0.
71	030171	2	252.	40.	2.50	13.90	352.	43.3	635.	14.5	563.	0.
72	030171	3	240.	30.	4.00	13.10	352.	43.9	665.	15.2	563.	0.
73	030171	4	270.	40.	3.40	13.40	351.	43.6	652.	15.0	565.	0.
74	030271	7	192.	50.	2.50	13.20	157.	21.4	314.	14.7	505.	121.
75	030271	8	222.	50.	1.70	13.60	154.	22.2	320.	14.4	505.	120.
76	030271	9	132.	70.	2.20	13.60	154.	21.4	312.	14.5	510.	119.
77	030271	10	108.	90.	2.30	13.30	154.	21.7	320.	14.8	500.	117.
78	030271	11	126.	50.	4.10	12.60	154.	21.9	335.	15.3	500.	115.
79	030271	12	150.	50.	3.43	13.00	153.	21.7	325.	15.0	508.	117.
80	030571	5A	324.	53.	2.40	13.80	353.	46.9	686.	14.6	565.	0.
81	030571	5B	305.	45.	2.80	13.50	353.	44.4	656.	14.8	570.	0.
82	030571	6A	349.	45.	2.60	13.30	353.	46.9	691.	14.7	568.	0.

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER H5

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
83	030571	6B	342.	50.	3.00	13.20	355.	44.4	660.	14.8	568.	0.
84	031771	1	154.	45.	3.30	13.30	150.	20.6	311.	14.9	503.	116.
85	031771	2	164.	45.	3.40	13.00	198.	25.7	400.	15.0	520.	114.
86	031771	3	180.	35.	2.90	13.40	250.	31.4	465.	14.8	523.	74.
87	031771	4	214.	35.	2.90	13.40	303.	37.5	555.	14.9	538.	0.
88	031771	5	265.	40.	2.80	13.50	352.	43.9	648.	14.8	565.	0.
89	032371	1	243.	-0.	3.30	12.90	150.	21.4	320.	15.0	510.	115.
90	032371	2	307.	-0.	2.70	13.50	300.	37.5	552.	14.7	540.	0.
91	032371	3	360.	-0.	2.70	13.50	350.	44.4	655.	14.7	565.	0.
92	032371	4	419.	-0.	3.10	13.20	350.	44.4	661.	14.9	565.	0.
93	012772	1	239.	-0.	3.00	13.10	350.	43.6	648.	14.9	563.	0.
94	103172	1	202.	10.	5.15	11.60	195.	26.4	416.	15.8	500.	82.
95	103172	2	213.	10.	4.45	12.30	155.	21.1	325.	15.4	500.	110.
96	103172	3	198.	10.	4.35	12.30	255.	31.9	491.	15.4	515.	0.
97	103172	4	221.	10.	4.15	12.85	302.	36.1	551.	15.3	528.	0.
98	103172	5	245.	10.	4.40	12.60	302.	36.1	555.	15.4	538.	0.

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LOW SULFUR OIL FUEL              BURNER CONFIGURATIONS FOR BOILER H3

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

50 022371 0      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2    1.
51 022371 1A     1  1  1  1  2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2    0.
52 022371 1AA    1  1  1  1  2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2    0.
53 022371 1B     1  1  1  1  2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2    1.
54 022471 2A     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    0.
55 022471 2B     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
56 022471 3A     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    0.
57 022471 3B     2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
58 030171 6      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
59 030171 5      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
70 030171 1      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    0.
71 030171 2      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    1.
72 030171 3      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    1.
73 030171 4      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    0.
74 030271 7      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
75 030271 8      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
76 030271 9      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    0.
77 030271 10     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    1.
78 030271 11     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    1.
79 030271 12     2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  2  1  2  2  1  2    0.
80 030571 5A     2  2  2  2  2  2  1  1  2  2  1  1  2  2  2  2  1  1  2  2  1  1  2  2    0.
81 030571 5B     2  2  2  2  2  2  1  1  2  2  1  1  2  2  2  2  1  1  2  2  1  1  2  2    1.
82 030571 6A     2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  2  1  1  2  1  1  1  1  1    0.
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LOW SULFUR OIL FUEL            BURNER CONFIGURATIONS FOR BOILER 45

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

83 030671 66     2  2  2  2  2  2  2  2  2  2  2  2  2  2  1  2  1  1  2  1  1  1  1  1     1.
84 031771 1      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
85 031771 2      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
86 031771 3      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
87 031771 4      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
88 031771 5      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
89 032371 1      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
90 032371 2      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
91 032371 3      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     1.
92 032371 4      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2     0.
93 012772 1      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
94 103172 1      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
95 103172 2      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     0.
96 103172 3      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
97 103172 4      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     1.
98 103172 5      2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2     0.
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LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER 46

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
99	121570	1	324.	-0.	3.40	12.85	150.	20.6	308.	15.0	543.	117.
100	121570	2	256.	-0.	3.53	13.65	150.	20.6	309.	15.0	543.	132.
101	121570	3	364.	-0.	2.75	13.68	250.	31.1	458.	14.7	551.	0.
102	121570	4	365.	-0.	2.98	13.70	250.	31.1	460.	14.8	551.	0.
103	121570	5	471.	-0.	2.98	13.29	348.	45.3	672.	14.8	545.	0.
104	121570	6	402.	-0.	3.05	13.40	348.	45.3	672.	14.8	545.	0.
105	121570	7	481.	-0.	2.03	14.10	348.	45.0	652.	14.5	545.	0.
106	121570	8	354.	-0.	2.25	14.10	348.	45.0	655.	14.5	545.	0.
107	082471	1	220.	-0.	3.09	13.30	150.	19.2	285.	14.9	543.	118.
108	082471	1A	256.	13.	3.51	14.00	150.	19.2	287.	14.9	543.	118.
109	082471	2	266.	15.	3.00	14.80	220.	26.1	414.	14.7	550.	0.
110	082471	2A	225.	13.	3.05	13.20	220.	28.1	418.	14.9	550.	0.
111	082471	3	286.	15.	3.09	13.35	290.	37.0	550.	14.9	550.	0.
112	082471	3A	317.	20.	3.22	14.50	290.	37.0	549.	14.9	550.	0.
113	082471	4	382.	13.	2.75	14.90	345.	44.0	646.	14.7	545.	0.
114	082471	4A	355.	13.	3.03	13.40	345.	44.0	654.	14.8	546.	0.
115	090171	1	190.	15.	2.20	14.60	250.	31.1	452.	14.5	550.	0.
116	090171	2	210.	17.	2.23	14.80	300.	38.1	553.	14.5	555.	0.
117	090171	3	260.	20.	2.41	14.40	350.	43.6	636.	14.6	563.	0.
118	090171	4	155.	25.	2.20	13.60	200.	25.0	364.	14.6	545.	0.
119	090171	5	150.	20.	2.80	13.30	150.	18.1	267.	14.9	545.	134.
120	071972	1	215.	10.	3.55	13.15	350.	44.4	668.	15.0	523.*	0.

*Some Air Preheater Baskets Removed

```
LOW SULFUR OIL FUEL              BURNER CONFIGURATIONS FOR BOILER H5

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

 99 121570 1      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
100 121570 2      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
101 121570 3      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
102 121570 4      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
103 121570 5      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
104 121570 6      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
105 121570 7      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
106 121570 8      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
107 082471 1      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
108 082471 1A     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
109 082471 2      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
110 082471 2A     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
111 082471 3      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
112 082471 3A     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
113 082471 4      2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    0.
114 082471 4A     2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2  2    1.
115 090171 1      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
116 090171 2      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
117 090171 3      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
118 090171 4      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
119 090171 5      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
120 071372 1      2  2  2  2  2  2  2  2  1  1  1  1  2  2  2  2  2  2  2  2  1  1  1  1    1.
```

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER S1

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
121	111770	1	159.	-0.	3.33	12.78	120.	16.4	246.	15.0	522.	67.
122	111770	2	155.	-0.	2.36	13.72	153.	20.3	296.	14.6	538.	43.
123	111770	3	174.	-0.	2.23	13.69	178.	23.8	347.	14.5	540.	16.
124	111870	4	149.	-0.	4.30	12.07	43.	6.3	95.	15.4	465.	81.
125	111870	5	143.	-0.	3.94	12.40	62.	8.9	135.	15.2	475.	83.
126	112070	7	146.	-0.	3.39	12.48	80.	11.7	175.	15.0	492.	71.
127	112070	8	147.	-0.	3.35	12.73	101.	14.2	212.	15.0	512.	53.
128	112070	9	233.	-0.	3.00	13.25	178.	23.9	355.	14.8	545.	35.
129	112370	A1	231.	-0.	1.18	14.15	148.	20.0	285.	14.2	535.	52.
130	112370	A2	142.	-0.	3.23	12.90	149.	20.3	303.	14.9	538.	45.
131	112370	A3	165.	-0.	3.00	12.96	150.	20.3	301.	14.9	538.	43.
132	112370	A4	13[illegible].	-0.	2.98	13.00	148.	20.3	301.	14.9	543.	55.
133	112570	B2	152.	-0.	3.13	12.75	152.	20.7	309.	14.9	535.	47.
134	112570	B3	145.	-0.	3.30	12.73	152.	20.8	312.	15.0	533.	47.
135	112570	C2A	259.	-0.	1.35	14.33	152.	20.3	290.	14.3	534.	47.
136	112570	C2B	165.	-0.	2.88	13.20	152.	20.6	304.	14.8	536.	54.
137	120170	D1A	129.	-0.	3.83	12.23	140.	19.0	289.	15.2	528.	41.
138	111671	2	183.	-0.	4.73	11.50	180.	23.6	369.	15.5	537.	13.

```
LOW SULFUR OIL FUEL                    BURNER CONFIGURATIONS FOR BOILER S1

NO.  DATE   TEST  1  2  3  4  5  6  7  8  9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 NOX PORTS

121 111773 1      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
122 111773 2      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
123 111773 3      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
124 111473 4      0  0  0  0  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
125 111473 5      0  0  0  0  0  0  0  0  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
126 112073 7      0  0  0  0  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
127 112073 8      0  0  0  0  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
128 112073 9      2  2  2  2  2  2  2  2  2  2  2  2  1  1  1  1  0  0  0  0  0  0  0  0    0.
129 112373 A1     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
130 112373 A2     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
131 112373 A3     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
132 112373 A4     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
133 112573 B2     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
134 112573 B3     2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
135 112573 C2A    2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
136 112573 C2B    2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
137 120173 D13    2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
138 110471 2      2  2  2  2  2  1  1  2  1  2  2  1  2  2  2  2  0  0  0  0  0  0  0  0    0.
```

LOW SULFUR OIL FUEL

OPERATING DATA FOR BOILER S2

NO.	DATE	TEST	NO (PPM)	CO (PPM)	O2 (PCT)	CO2 (PCT)	LOAD (MW)	FUEL FLOW (LBS/SEC)	AIR FLOW (LBS/SEC)	AIR FUEL RATIO	COMB. AIR TEMP. (F)	FGR FLOW (LBS/SEC)
139	113070	1	126.	-0.	4.83	11.78	41.	6.3	98.	15.5	492.	84.
140	113070	2	136.	-0.	4.53	12.13	59.	8.6	133.	15.5	510.	81.
141	113070	3	156.	-0.	4.00	12.08	81.	11.1	171.	15.4	517.	74.
142	113070	4	152.	-0.	4.33	12.28	99.	13.3	205.	15.4	519.	50.
143	120170	5	132.	-0.	3.23	12.36	120.	15.8	237.	15.0	525.	67.
144	120170	6	140.	-0.	2.63	13.00	149.	18.9	273.	14.7	536.	43.
145	120170	7	153.	-0.	3.88	12.13	179.	22.8	347.	15.2	546.	26.
146	020871	1	276.	30.	4.83	12.57	78.	10.8	167.	15.4	504.	35.
147	020871	2	198.	-0.	2.04	14.79	77.	10.8	157.	14.5	502.	85.
148	020871	3	288.	40.	4.63	12.72	121.	15.1	249.	15.6	523.	35.
149	020871	4	235.	30.	1.72	14.90	119.	15.6	224.	14.4	529.	74.
150	020871	5	342.	53.	3.53	13.10	181.	23.1	349.	15.1	550.	8.
151	020871	6	247.	-0.	1.75	14.71	181.	22.8	329.	14.4	553.	25.
152	020971	1	158.	20.	3.48	13.39	179.	23.1	345.	15.0	546.	0.
153	020971	2	191.	-0.	4.76	12.50	178.	22.8	353.	15.5	542.	9.
154	020971	3	210.	-0.	4.49	12.38	179.	22.9	356.	15.5	547.	19.
155	020971	4	179.	-0.	3.71	13.40	179.	22.8	343.	15.1	551.	9.
156	020971	5	364.	-0.	4.45	12.84	119.	15.6	239.	15.4	535.	57.
157	020971	6	316.	-0.	2.40	14.49	119.	15.8	231.	14.6	533.	65.
158	021071	1	138.	43.	3.31	12.82	179.	23.1	350.	15.2	552.	14.
159	021071	2	184.	30.	5.39	11.52	120.	15.8	251.	15.9	537.	32.
160	021071	3	156.	50.	1.76	14.43	118.	15.6	224.	14.4	527.	72.
161	021071	4	232.	30.	3.09	13.39	180.	22.8	339.	14.9	542.	9.

LOW SULFUR OIL FUEL   BURNER CONFIGURATIONS FOR BOILER 52

NO.	DATE	TEST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	NOX PORTS
139	113070	1	0	0	0	0	0	0	0	0	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
140	113070	2	0	0	0	0	0	0	0	0	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
141	113070	3	0	0	0	0	2	0	0	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
142	113070	4	0	0	0	0	2	0	0	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
143	120170	5	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
144	120170	6	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
145	120170	7	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
146	020871	1	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
147	020871	2	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
148	020971	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
149	020871	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
150	020971	5	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
151	020871	6	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
152	020971	1	2	2	2	2	2	0	0	2	0	2	2	0	2	2	2	2	0	0	0	0	0	0	0	0	0.
153	020971	2	2	2	2	2	2	0	0	2	0	2	2	0	2	2	2	2	0	0	0	0	0	0	0	0	0.
154	020971	3	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
155	020971	4	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
156	020971	5	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
157	020971	6	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
158	021071	1	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
159	021071	2	2	2	2	2	2	1	1	2	1	2	2	1	2	2	2	2	0	0	0	0	0	0	0	0	0.
160	021071	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.
151	021071	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0.

APPENDIX E

EFFECT OF PARTIAL REACTION WITHIN A BURNER ON THE RESISTANCE TO AIR FLOW THROUGH THE BURNER

The data shown in Section 3, Figure 3-2 indicate that the admittance to air flow of an (F+A) burner is a function of the air flow velocity through the burner, presumably from the effect of the air velocity on the fraction of combustion completed within the burner. As a means of substantiating this assumption, it was considered necessary, however, to independently calculate the fraction of combustion which must occur within the burner to result in the measured admittance values. The values of ADMNP and ADMA estimated from the data of Figure 3-2 must be at least sufficiently correct that the independent calculations of ADMFA match the experimental ones with fractions of combustion within the burner ranging from zero to one. As in Figure 3-2, a value of 2.05 metric (10, English) was assigned to both ADMNP and ADMA. Independent analyses by engineers associated with the utility confirm that these two admittances are approximately equal.

For this analysis, an operating (F+A) burner was divided into three sections: (a) the inlet section, consisting largely of air register and inlet resistance to pure air flow (R_1), (b) a cold mixing section, including all of the unreacted air-fuel mixing and momentum interchange (R_2), and (c) a constant-area heat-addition section, extending to the exit of the burner, where some fraction C_h of the reactants are consumed (R_3). As mentioned in Section 3.2.1, the effect of momentum interchange in the cold gas mixing section was found to be negligible and, therefore, R_2 was set equal to zero. The air flow resistance of an (F+A) burner then was defined:

$$R_{fa} = R_1 + R_3 \qquad \text{(E-1)}$$

With no heating due to reaction, R_3 also becomes zero, and all resistance is assumed to be due to air register and inlet losses, identical with those in an (Air) burner. Therefore, it is seen that

$$R_1 = \frac{1}{(ADMA)^2} \qquad \text{(E-2)}$$

Letting ADMA be equal to 2.05 (10) as estimated earlier, ADMFA values and the air flow velocities in the (F+A) burners can be calculated for each unique test condition. The ADMFA values can be converted to values of R_3. R_3 is defined, as in Section 3, Eq. (3-9):

$$R_3 = \frac{\Delta P_3}{\dot{w}^2} \qquad \text{(E-3)}$$

The basic momentum equation can be written in differential form as

$$dp + \rho v dv = 0 \quad \text{(in units of force/unit area)} \qquad \text{(E-4)}$$

Using the continuity equation for steady flow in a constant area duct, Eq. (E-4) can be written:

$$dp - v^2 d\rho = 0 \qquad \text{(E-5)}$$

From the perfect gas law, it is found:

$$d\rho = \rho \left(\frac{dp}{p} - \frac{dT}{T}\right) \qquad \text{(E-6)}$$

In this case, the entire pressure drop (dp) through the burner is small compared with the mean pressure level (p), while the temperature change due to heating (dT) can be very large compared with the mean temperature (T). Therefore, dp/p can be neglected compared to dT/T, and density variations become a function of temperature variations only:

$$d\rho = - \frac{\rho}{T}\, dT \qquad \text{(E-7)}$$

The energy equation can now be written:

$$dp + \left(\frac{\dot{w}^2}{g\gamma A^2 T}\right) dT = 0 \qquad \text{(E-8)}$$

but since

$$\gamma T = \frac{p}{R_o} M \qquad \text{(E-9)}$$

and variations in p are small within the burner, we can let

$$\gamma T = \gamma_a T_a \qquad \text{(E-10)}$$

Then, it is seen that

$$dp + \left(\frac{\dot{w}^2}{g\gamma_a A^2 T_a}\right) dT = 0 \qquad \text{(E-11)}$$

and across the heat release section of the burner that

$$p_1 - p_2 = \left(\frac{\dot{w}^2}{g\gamma_a A^2 T_a}\right) (T_2 - T_1) \qquad \text{(E-12)}$$

Define the heat release due to combustion:

$$\dot{q} = \dot{w}_f q_f C_h \qquad \text{(E-13)}$$

and constant pressure heating:

$$\dot{q} = \dot{w}\, C_p \,(T_2 - T_1) \qquad \text{(E-14)}$$

Then, it is found that

$$T_2 - T_1 = \frac{\dot{w}_f q_f}{\dot{w}\, C_p} C_h \qquad \text{(E-15)}$$

and

$$p_1 - p_2 = \left(\frac{\dot{w}^2}{g\gamma_a A^2 T_a}\right) \left(\frac{\dot{w}_f}{\dot{w}}\right) \frac{q_f}{C_p} C_h \qquad \text{(E-16)}$$

Equation (E-16) can be expressed in terms of the air flow by noting:

$$\dot{w} = \dot{w}_a \left(\frac{1 + r_b}{r_b} \right) \tag{E-17}$$

and

$$\dot{w}_f = \frac{\dot{w}}{1 + r_b} \tag{E-18}$$

Finally,

$$p_1 - p_2 = \left[\frac{1}{g\gamma_a A^2} \left(\frac{C_h q_f}{C_p T_a} \right) \left(\frac{1 + r_b}{r_b^2} \right) \right] \dot{w}_a^2 \tag{E-19}$$

Noting that

$$p_1 - p_2 = R_3 \dot{w}_a^2 \tag{E-20}$$

$$R_3 = \frac{1}{g\gamma_a A^2} \left(\frac{C_h q_f}{C_p T_a} \right) \left(\frac{1 + r_b}{r_b^2} \right) \tag{E-21}$$

Using the values:

γ_a = 0.5241 kg/m^3 (0.03972 lb/ft^3)

A = 0.6567 m^2 (7.069 ft^2)

q_f = 11,700 kg-cal/kg (21,000 Btu/lb) of fuel

Cp = 0.24 kg-cal/kg-°K (0.24 Btu/lb-°R) (air)

$T_a = 567\,°K\ (1020\,°R)$

Using the English units, Eq. (E-21) becomes:

$$R_3 = 1.371 \left(\frac{1 + r_b}{r_b^2}\right) C_h \qquad \text{(E-22)}$$

Values of C_h (the fraction of combustion completed in the burner) were calculated from Eq. (E-22) by the following procedure:

a. Calculate total admittance ADMT.

b. Subtract ADMNP and the sum of ADMA for the (Air) burners.

c. Calculate ADMFA for the (F+A) burners.

d. Calculate R_3 from ADMFA and R_1.

e. Calculate air flow through the (F+A) burners from the admittance ratios.

f. Calculate fuel flow in the (F+A) burners.

g. Calculate r_b.

h. Calculate C_h.

The resulting values of C_h for all available gas-fired data from the H3 boiler are shown in Figure 3-3. The C_h values for gas-fired data lie between zero and one. Calculations for the oil data shown in Figure 3-3 also indicate C_h values near zero, as expected. The values of ADMNP and ADMA appear to be approximately correct. Values of ADMA, then were estimated for all other boiler types, where data were available, from a procedure such as shown in Figure 3-2.

NOMENCLATURE FOR APPENDIX E

The following is a list of terms used in the equations of this Appendix. Other terms used in this Appendix can be found in the "Nomenclature" of the text.

A = cross-sectional area of a burner, m^2 (ft^2)

C_p = specific heat of reaction products, kg-cal/kg-°K (Btu/lb-°R)

g = acceleration of gravity, m/sec^2 (ft/sec^2)

p = static pressure, kg/m^2 (abs) (lb/ft^2)

ΔP = pressure drop, kg/m^2 (diff) (lb/ft^2)

q = heat of reaction, kg-cal/kg (Btu/lb) of fuel reacted

$\dot{q}$ = rate of heat generation due to reaction, kg-cal/sec (Btu/sec)

R_{fa} = overall air flow resistance of an (F+A) burner, $sec^2/kg\text{-}m^2$ ($sec^2/lb\text{-}ft^2$)

R_1, R_2, R_3 = air flow resistance in (a) the air-only inlet section, (b) the cold air-fuel mixing section, and (c) the reaction section of an (F+A) burner, $sec^2/kg\text{-}m^2$ ($sec^2/lb\text{-}ft^2$)

r = A/F ratio, by weight

γ = weight density, kg/m^3 (lb/ft^3)

Subscripts

1 = conditions at the upstream end of the reaction section of an (F+A) burner

2 = same as (1), at the burner exit